4.3 AIR QUALITY

This section describes environmental and regulatory settings related to air quality in the Project area; identifies air quality impacts of the proposed Project, the Alternatives and the cumulative projects; and provides potential mitigation measures.

4.3.1 Environmental Setting

Regional Overview

The proposed Project area is located within the South Central Coast Air Basin (SCCAB) in southwestern Santa Barbara county within the city of Goleta. The region has a Mediterranean climate characterized by mild winters, and warm, dry summers. The influence of the Pacific Ocean causes mild temperatures year-round along the coast, while inland areas experience a wider range of temperatures. Table 4.3-1 summarizes the climatic data collected at the weather station located closest to the Project area, which is the Santa Barbara Weather Station.

Table 4.3-1
Climatic Data for the Project Area

Parameter	Santa Barbara
Monthly Mean Range max. T	65.5 to 78.7°F (18.6–25.9°C)
Monthly Mean Range min. T	39.9 to 58.4°F (4.4–14.7°C)
Normal Daily T Range	40 to 79°F (4.4–26.1°C)
Average Annual Precipitation	18.6 inches (0.47 m)
Mean Precipitation Range	0.02 inches (0.05 cm) (July) to 4.07 inches (0.1 m) (February)

Notes: T = temperature; °F = degrees Fahrenheit, °C = degrees Celsius; cm = centimeters; m = meters
Source: National Weather Forecast Office 2004; Western Regional Climate Center 2004

Precipitation is confined primarily to the winter months. Occasionally, tropical air masses result in rainfall during summer months. Annual precipitation in the region varies widely over relatively short distances, primarily due to topographical effects. The long-term annual total precipitation along the coast is approximately 12 to 16 inches (0.3 to 0.4 meters [m]), but on mountaintops, totals are nearly 30 inches (0.7 m).

The regional climate is dominated by a strong and persistent high-pressure system, which frequently lies off the Pacific Coast (generally referred to as the East Pacific Subtropical High-Pressure Zone or Pacific High). The Pacific High shifts northward or southward in response to seasonal changes or the presence of cyclonic storms. In its usual position to the west, the high produces an elevated temperature inversion. An inversion is characterized by a layer of warmer air aloft, and cooler air near the ground surface. Normally, air temperature decreases with altitude. In an inversion, the temperature of a layer of air increases with altitude. The inversion acts like a lid on the cooler air mass near the ground, preventing pollutants in the lower air mass from dispersing upward beyond the inversion “lid.” This phenomenon results in higher concentrations of pollutants trapped below the inversion.

Atmospheric stability is a primary factor that affects air quality in the study region. Atmospheric stability regulates the amount of air exchange (referred to as turbulent mixing) both horizontally and vertically. Restricted atmospheric turbulence, that is, a high degree of stability, and low wind speeds are generally associated with higher pollutant concentrations. These conditions are typically related to temperature inversions that cap the pollutants emitted below or within them.

Airflow plays an important role in the movement of pollutants. Regional winds are normally controlled by the location of the Pacific High. Wind speeds typical of the region are generally light, another factor that contributes to higher levels of pollution, since low wind speeds minimize dispersion of pollutants. The sea breeze is typically northwesterly throughout the year; however, local topography causes variations. During summer months, these northwesterly winds are stronger and persist later into the night. When the Pacific High weakens, a Santa Ana condition can develop, with air traveling westward into the county from the east. Stagnant air often occurs at the end of a Santa Ana condition, causing a buildup of pollutants offshore. Prevailing wind speeds on the coast range from nine to 11.5 miles per hour (mph) (14.5 to 18.5 kilometers per hour [km/h]), with maximum gusts up to 70 to 80 mph (112.7 to 128.7 km/h).

Several types of inversions are common to the area. In winter, weak surface inversions occur, caused by radiation cooling of air in contact with the cold surface of the earth. During spring and summer, marine inversions occur when cool air from over the ocean intrudes under the warmer air that lies over the land. During the summer, the Pacific High can cause the air mass to sink, creating a subsidence inversion.

Topography plays a significant role in affecting the direction and speed of winds. During the months of May to October, inversions commonly form in the Project area. Year round, light onshore winds hamper the dispersion of primary pollutants, and the orientation of the inland mountain ranges interrupt air circulation patterns. Pollutants become trapped, creating ideal conditions for the production of secondary pollutants in the coastal zones.

Air Quality

Air quality is determined by measuring ambient concentrations of air pollutants, which are known to have adverse health effects. For regulatory purposes, standards have been set for some of these air pollutants, and they are referred to as “criteria pollutants.” For most criteria pollutants, regulations and standards have been in effect, in varying degrees, for more than 25 years, and control strategies are designed to ensure that the ambient concentrations do not exceed certain thresholds. Another class of air pollutants that are subject to regulatory requirements is called hazardous air pollutants (HAPs) or air toxics. Substances that are especially harmful to health, such as those considered under the U.S. EPA hazardous air pollutant program or California’s AB 1807 and/or AB 2588 air toxics programs, are considered to be air toxics. Regulatory air quality standards are based on scientific and medical research. These standards establish minimum concentrations of an air pollutant in the ambient air that could initiate adverse health effects.

For air toxics emissions, however, the regulatory process usually assesses the potential impacts to public health in terms of “risk,” such as the Air Toxics “Hot Spots” Program in California, or the emissions may be controlled by prescribed technologies, as in the Federal Clean Air Act approach for controlling hazardous air pollutants.

The degree of air quality degradation for criteria pollutants is determined by comparing the ambient pollutant concentrations to health-based standards developed by government agencies. The current National Ambient Air Quality Standards (NAAQS) and California Ambient Air Quality Standards (CAAQS) for “criteria pollutants” are listed in Table 4.3-2. Ambient air quality monitoring for criteria pollutants is conducted at numerous sites throughout California. Table 4.3-3 presents relevant data from several monitoring stations located in the Project area. A summary of the attainment status for Santa Barbara county is provided in Table 4.3-4. Ambient air quality in the county is generally good, i.e., within applicable ambient air quality standards, with the exception of particulate matter with an aerodynamic diameter of ten microns or less (PM_{10}), and ozone (O_3).

Table 4.3-2
Ambient Air Quality Standards for Criteria Pollutants

Pollutant	Averaging Time	California [1, 3] Standards	National Standards [2]	
			Primary [4]	Secondary [3, 5]
Ozone (O_3)	1-hour [2] 8-hour [1]	0.09ppm (180μg/m^3) 0.07ppm (137μg/m^3)	0.12ppm [2] 0.08ppm (157μg/m^3)	0.12ppm 0.08ppm (157μg/m^3)
Carbon Monoxide (CO)	8-hour 1-hour	9.0ppm (10mg/m^3) 20.0ppm (23mg/m^3)	9.0ppm (10mg/m^3) 35ppm (40mg/m^3)	NS NS
Nitrogen Oxide (NO_2)	Annual Avg. 1-hour	NS 0.25ppm (470μg/m^3)	0.053ppm (100μg/m^3) NS	0.053ppm (100μg/m^3) NS
Sulfur Dioxide (SO_2)	Annual Avg. 24-hour 3-hour 1-hour	NS 0.04ppm (105μg/m^3) NS 0.25 ppm (655μg/m^3)	0.03ppm (80μg/m^3) 0.14ppm (365μg/m^3) NS NS	NS NS 0.5ppm (1,300μg/m^3) NS
PM_{10}	Annual Arithmetic Mean 24-hour	20μg/m^3 50μg/m^3	revoked 150μg/m^3	NS 150μg/m^3
$PM_{2.5}$	Annual Arithmetic Mean 24-hour	12μg/m^3 NS	15μg/m^3 35μg/m^3	15μg/m^3 35μg/m^3
Sulfates (SO_4^{-2})	24-hour	25μg/m^3	NS	NS
Lead (Pb) [6]	30-day Avg. Calendar Qtr.	1.5μg/m^3 NS	NS 1.5μg/m^3	NS 1.5μg/m^3
Hydrogen Sulfide (H_2S)	1-hour	0.03ppm (42μg/m^3)	NS	NS
Vinyl Chloride [6]	24-hour	0.01ppm (26μg/m^3)	NS	NS
Visibility Reducing Particles	1 Observation	Insufficient amount to reduce the prevailing visibility [7] to less than ten miles when the relative humidity is less than 70 percent (CA only).		

Notes: ppm = parts per million by volume (micromoles of pollutant per mole of gas) μg/m^3 = microgram/cubic meter; mm = millimeter; NS = No Standard; Avg. = Average

[1] California standards for O_3, CO, SO_2 (1-hour), NO_2, $PM_{2.5}$ and PM_{10} are values that are not to be exceeded. SO_4^{-2}, Pb, H_2S, Vinyl Chloride, and visibility-reducing particles standards are not to be equaled or exceeded. Sulfates are pollutants that include SO_4^{-2} ion in their molecule. CA 8-hr O_3 standard is effective as of 5/17/06.

[2] National Standards, other than O_3 and those based on an annual average or annual arithmetic mean, are not to be exceeded more than once a year. The O_3 Standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is equal to or less than one. National 1-hour O_3 standard was revoked on June 30, 2005. The 1-hour O_3 standard applies only in 14 8-hour O_3 non-attainment areas.

[3] Concentration expressed first in units in which it was promulgated. Equivalent units in parentheses are based upon reference temperature of 25°C and a reference pressure of 760 mm of mercury (1,013.2 millibar). All measurements of air quality are to be corrected to these reference conditions.

[4] National Primary Standards: The levels of air quality necessary, with an adequate margin of safety, to protect the public health. Each State must attain the primary standards no later than three years after that State's implementation plan is approved by the US EPA.

[5] National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant. Each State must attain the secondary standards within a "reasonable time" after the implementation plan is approved by the US EPA.

[6] The California Air Resources Board (CARB) has identified lead and vinyl chloride as 'toxic air contaminants' with no threshold level of exposure for adverse health effects determined. These actions allow for the implementation of control measures at levels below the ambient concentrations specified for these pollutants.

[7] Prevailing visibility is defined as the greatest visibility, which is attained or surpassed around at least half of the horizon circle, but not necessarily in continuous sectors.

Source: CARB 2006a, EPA 2006

Table 4.3-3
Ambient Air Quality Summary for the Project Area, 2004 - 2006

			Maximum Observed Concentration (# of Days Standard was Exceeded) [8]	
Pollutant		**Year**	**Goleta - Fairview**	**Santa Barbara**
Ozone, ppm	1-hour 8-hour	2004	0.092 (0) **0.087 (1 day)**	**0.095 (1 day)** **0.085 (1 day)**
	1-hour 8-hour	2005	0.080 (0) 0.066 (0)	0.077 (0) 0.064 (0)
	1-hour 8-hour	2006	0.083 (0) 0.069 (0)	0.075 (0) 0.061 (0)
CO, ppm	8-hour	2004	0.95 (0)	1.93 (0)
	8-hour	2005	0.83 (0)	1.66 (0)
	8-hour	2006	0.80 (0)	1.81 (0)
NO_2, ppm	1-hour Annual Average	2004	0.043 (0) 0.009	0.063 (0) 0.013
	1-hour Annual Average	2005	0.044 (0) 0.008	0.062 (0) 0.012
	1-hour Annual Average	2006	0.039 (0) 0.008	0.063 (0) NA
SO_2, ppm	1-hour Annual Average	2004	0.001 (0) NA	NA NA
	1-hour Annual Average	2005	0.001 (0) NA	NA NA
	1-hour Annual Average	2006	0.003 (0) NA	NA NA
$PM_{2.5}$, $\mu g/m^3$	24-hour Annual Arithmetic Mean	2004	NA NA	27.5 (0) NA
	24-hour Annual Arithmetic Mean	2005	NA NA	28.3 (0) NA
	24-hour Annual Arithmetic Mean	2006	NA NA	27.9 (0) NA

Notes:
The values are provided in the units promulgated by the US EPA
NA = No data available (the monitoring station does not monitor this pollutant)
[8] Number or percent of exceedance of the most restrictive standard (usually, the State Standard).
Source: CARB 2006b, http://www.arb.ca.gov/adam/welcome.html accessed 10/2007.

Table 4.3-4
Attainment Status of Santa Barbara County

1-hour O_3 [9]		Federal 8-hour O_3	CO		NO_2		SO_2		$PM_{2.5}$		PM_{10}	
CA	Fed		CA	Fed	CA	Fed	CA	Fed	CA	Fed	CA	Fed
N	na	A	A	A	A	U/A	A	U/A	U	U/A	N	U

Notes:
CA = California State Standards; A = Attainment of Standards; N = Non-attainment; U = Unclassified;
U/A = Unclassified/Attainment, na = not applicable.
[9] National 1-hours O_3 standard was revoked on June 30, 2005 with all applicable designations.
Source: CARB 2006c.

Criteria pollutants are also categorized as inert or photochemically reactive, depending on their subsequent behavior in the atmosphere. By definition, inert pollutants are relatively stable, and their chemical composition remains stable as they move and diffuse through the atmosphere. The photochemical pollutants may react to form secondary pollutants. For these pollutants, adverse health effects may be caused directly by the emitted pollutant or by the secondary pollutants.

Inert Pollutants

Criteria pollutants that are considered to be inert include carbon monoxide (CO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), PM, lead, sulfates, and hydrogen sulfide (H_2S).

Carbon monoxide is formed primarily by the incomplete combustion of organic fuels. Santa Barbara county is in attainment of the California and national 1-hour and 8-hour CO standards. High values are generally measured during winter, when dispersion is limited by morning surface inversions. Seasonal and diurnal variations in meteorological conditions lead to lower values in summer and in the afternoon.

Nitric oxide (NO) is a colorless gas formed during combustion processes that rapidly oxidizes to form nitrogen dioxide (NO_2), a brownish gas. Santa Barbara county is in attainment for the California and national nitrogen dioxide standards. The highest nitrogen dioxide values are generally measured in urbanized areas with heavy traffic.

Sulfur dioxide (SO_2) is a gas produced primarily from combustion of sulfurous fuels by stationary and mobile sources. Santa Barbara county has been in attainment of the California and national sulfur dioxide standards for the last 10 years.

The largest PM_{10} emissions appear to originate from soils via roads, construction, agriculture, and natural, windblown dust. Other sources of PM_{10} include sea salt, particulate matter released during combustion processes, such as those in gasoline and diesel vehicles, and wood burning. Also, nitrogen oxides (NO_x) and sulfur oxides (SO_x) are precursors in the formation of secondary PM_{10}. Santa Barbara county is in exceedance of the California 24-hour PM_{10} standard (see Table 4.3-4). Santa Barbara county is Unclassified for the recently added State $PM_{2.5}$ Standard.

Lead is a heavy metal that in ambient air occurs as a lead oxide aerosol or dust. Since lead is no longer added to gasoline or to paint products, lead emissions have been reduced significantly in recent years. The county is in attainment with the NAAQS and the CAAQS for lead.

Sulfates are aerosols, i.e., wet particulates, which are formed by sulfur oxides in moist environments. They exist in the atmosphere as sulfuric acid and sulfate salts. The primary source of sulfate is from the combustion of sulfurous fuels. The county is in attainment for the California sulfate standard, and there has been a steady decrease in ambient concentrations in the recent decade.

Hydrogen sulfide (H_2S) is an odorous, toxic, gaseous compound that can be detected by humans at very low concentrations. Concentrations detectable by smell (this can vary from 0.5 parts per billion [ppb] detected by two percent of the population, to 40 ppb, qualified as annoying by 50 percent of the population) are significantly lower than concentrations that could affect human health (2 ppm [2,000 ppb] can cause headaches and increased airway resistance in asthmatics; inhalation of 600 ppm is lethal). The gas is produced during the decay of organic material and is also found naturally in petroleum and natural gas. The county is in attainment of the H_2S standard.

Photochemical Pollutants

Ozone is formed in the atmosphere through a series of complex photochemical reactions involving oxides of nitrogen (NO_x), reactive organic compounds (ROC), and sunlight, occurring over a period of several hours. Since ozone is not emitted directly into the atmosphere, but is formed as a result of photochemical reactions, it is classified as a secondary or regional pollutant. Because these ozone-forming reactions take time, peak ozone levels are often found downwind of major source areas.

Santa Barbara county is not in attainment for the State 1-hour ozone standard. Santa Barbara county is in attainment for the Federal 8-hour ozone standard.

Hazardous Air Pollutants (HAPs)

HAPs are materials that are known or suspected to cause cancer, genetic mutations, birth defects, or other serious illnesses in humans. HAPs may be emitted from three main source categories: (1) industrial facilities; (2) internal combustion engines (stationary and mobile); and (3) small "area sources" (such as solvent use). The California Air Resources Board (CARB) publishes lists of Volatile Organic Compound Species Profiles for many industrial applications and substances (CARB 2006d).

Generally, HAPs behave in the atmosphere in the same general way as inert pollutants (those that do not react chemically, but preserve the same chemical composition from point of emission to point of impact). The concentrations of toxic pollutants are therefore determined by the quantity and concentration emitted at the source and the meteorological conditions encountered as the pollutants are transported away from the source. Thus, impacts from toxic pollutant emissions tend to be site-specific and their intensity is subject to constantly changing meteorological conditions. The worst-case meteorological conditions that negatively affect short-term impacts are low wind speeds, highly stable air mass, and constant wind direction.

Odorous Compounds

Several compounds associated with the oil and gas industry can produce odors that can be determined to be nuisances. Sulfur compounds, found in oil and gas, have very low odor threshold levels. For instance, H_2S can be detected by humans at concentrations from 0.5 parts per billion [ppb] (detected by two percent of the population), to 40 ppb, qualified as annoying by 50 percent of the population. These levels are significantly lower than concentrations that could affect human health (2 ppm [2,000 ppb] can cause headaches and increased airway resistance in asthmatics; inhalation of 100 ppm can be lethal [ERPG-3]).

Many volatile compounds found in oil and gas (ethane and longer chain hydrocarbons) typically have petroleum or gasoline odor with various odor thresholds.

Natural gas contains mostly methane (which is odorless), thus it has to be odorized as dictated by law, before being placed into a distribution pipeline. The various odorizing compounds that are used for odorization, contain sulfur compounds having a very low odor threshold and can produce odors if released into the atmosphere.

Greenhouse Gases

Greenhouse gases (GHGs) are defined as any gas that absorbs infrared radiation in the atmosphere. Greenhouse gases include, but are not limited to, water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O) and fluorocarbons. These greenhouse gases lead to the trapping and buildup of heat in the atmosphere near the earth's surface, commonly known as the "greenhouse effect". The accumulation of greenhouse gases in the atmosphere regulates the earth's temperature. Without natural greenhouse gases, the Earth's surface would be cooler (CA 2006). Emissions from human activities, such as electricity production and vehicles, have elevated the concentration of these gases in the atmosphere. There is increasing evidence that the greenhouse effect is leading to global warming and climate change (EPA 2000).

Greenhouse gases have varying global warming potential (GWP). The GWP is the potential of a gas or aerosol to trap heat in the atmosphere. Because GHG absorb different amounts of heat, a common reference gas (CO_2) is used to relate the amount of heat absorbed to the amount of the gas emissions, referred to as "CO_2 equivalent" and is the amount of GHGs emitted multiplied by the GWP. The GWP of CO_2 is defined as one, whereas the GWP of methane, for example, is 21, meaning that methane gas absorbs 21 times as much heat, and therefore has 21 times greater impact on global warming per pound of emissions, as CO_2.

Global climate change considered by many scientists to be caused by GHG emissions is currently one of the most important and widely debated scientific, economic, and political issues in the United States. Global climate change is a change in the average weather of the earth, which can be measured by wind patterns, storms, precipitation, and temperature. Historical records have shown that temperature changes have occurred in the past, such as during previous ice ages. Some data indicate that the current temperature record differs from previous climate changes in rate and magnitude (AEP 2007). These climate changes could lead to various changes in weather, rainfall patterns and increasing sea level leading to flooding.

Water vapor is the most abundant and variable greenhouse gas in the atmosphere. It is not considered a pollutant; in the atmosphere it maintains a climate necessary for life. The main source of water vapor is evaporation from the oceans (approximately 85 percent). Other sources include evaporation from other water bodies, sublimation (change from solid to gas) from ice and snow, and transpiration from plant leaves (AEP 2007).

Carbon dioxide (CO_2) is an odorless, colorless greenhouse gas. Natural sources include decomposition of dead organic matter; respiration of bacteria, plants, animals, and fungus; evaporation from oceans; and volcanic outgassing. Anthropogenic (human caused) sources of carbon dioxide include burning fuels, such as coal, oil, natural gas, and wood. Concentrations are currently around 370 ppm in the atmosphere; some say that concentrations may increase to 540 ppm by 2100 as a direct result of anthropogenic sources (IPCC 2001). Some predict that this will result in an average global temperature rise of at least 2° Celsius ([3.6 °F] IPCC 2001).

Methane is a gas and is the main component of natural gas used in homes. It has a GWP of about 21. A natural source of methane is from the decay of organic matter. Geological deposits known as natural gas fields contain methane, which is extracted for fuel. Other sources are from decay of organic material in landfills, fermentation of manure, and cattle.

Nitrous oxide (N_2O) is a colorless gas. It has a GWP of about 310. Nitrous oxide is produced by microbial processes in soil and water, including those reactions which occur in fertilizer containing nitrogen. In addition to agricultural sources, some industrial processes (nylon production, nitric acid production) also emit N_2O. It is used in rocket engines, as an aerosol spray propellant, and in race cars. During combustion, NO_x (NO_x is a generic term for mono-nitrogen oxides, NO and NO_2) is produced as a criteria pollutant (see above), and is not the same as N_2O. Very small quantities of nitrous oxide (N_2O) may be formed during fuel combustion by reaction of nitrogen and oxygen (API 2004).

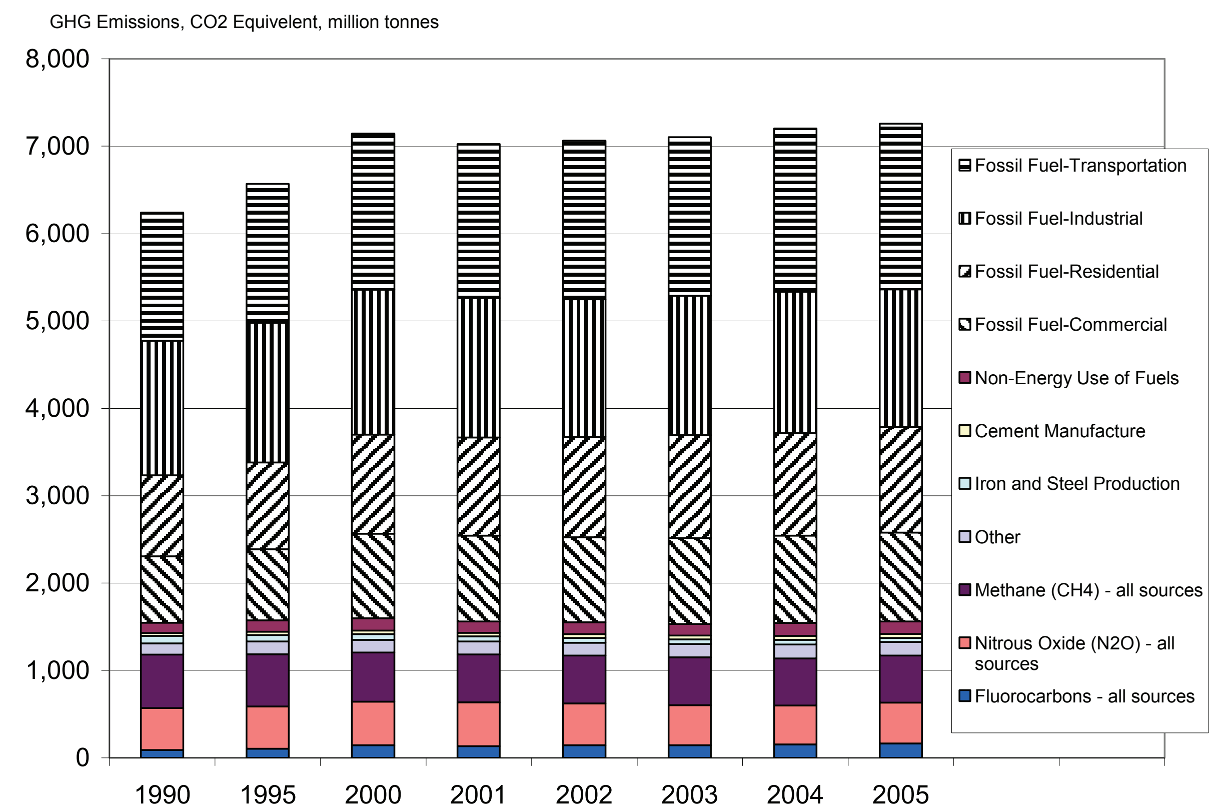
Chlorofluorocarbons (CFCs) are gases formed synthetically by replacing all hydrogen atoms in methane or ethane with chlorine and/or fluorine atoms. CFCs are nontoxic, nonflammable, insoluble, and chemically nonreactive in the troposphere (the level of air at the earth's surface). CFCs were first synthesized in 1928 for use as refrigerants, aerosol propellants, and cleaning solvents. They destroy stratospheric ozone; therefore their production was stopped as required by the Montreal Protocol. Hydrofluorocarbons (HFCs) are synthetic man-made chemicals that are used as a substitute for CFCs for automobile air conditioners and refrigerants. Perfluorocarbons (PFCs) are used in aluminum production and semiconductor manufacture industry Fluorocarbons have a GWP of between 140 and 11,700.

Sulfur hexafluoride (SF_6) is an inorganic, odorless, colorless, nontoxic, nonflammable gas. It also has the highest GWP of any gas - 23,900. Sulfur hexafluoride is used for insulation in electric power transmission and distribution equipment, in the magnesium industry, in semiconductor manufacturing, and as a tracer gas for leak detection.

Ozone is a greenhouse gas; however, unlike the other greenhouse gases, ozone in the troposphere is relatively short-lived and therefore is not global in nature. According to CARB, it is difficult to make an accurate determination of the contribution of ozone precursors (NOx and volatile organic compounds [VOCs]) to global warming (CARB 2004b).

Fossil fuel combustion represents the vast majority of the GHG emissions, with CO_2 being the primary GHG. The total U.S. GHG emissions was 7,260 million metric tons of carbon equivalents (MMTCE) in 2005, of which 84 percent was CO_2 emissions (EPA 2007). Figure 4.2-1 shows the breakdown of U.S. GHG emissions since 1990. Approximately 33 percent of GHG emissions were associated with transportation in 2005, and about 41 percent with electricity generation.

Figure 4.3-1
U.S. GHG Emissions



Source: EPA 2007
Note: Fossil fuel use includes electrical generation

California's greenhouse gas emissions are large in a world-scale context and continuing to grow over time. California greenhouse gas emissions would rank 16th largest in the world. In 2004, California produced 492 million metric tons of CO_2 equivalent GHG emissions (CEC 2006). The transportation sector is the single largest category of California's GHG emissions, producing 41 percent of the State's total GHG emissions in 2004. Electrical generation produced 22 percent of GHG emissions. Most of California's emissions, 81 percent, are carbon dioxide produced from fossil fuel combustion (CEC 2006).

The quantification of GHG emissions associated with a project can be complex. GHG emissions are global in that emissions from one location could affect the entire planet and are not limited to local impacts. Therefore a "lifecycle" type analysis must be conducted to evaluate the GHG emissions associated with the extraction of "raw material" through their "end use" cycle including the proposed Project's direct, indirect, and cumulative impact.

GHG emissions are classified as direct and indirect. Direct emissions are associated with any production of GHG emissions at the Project site. These would include the combustion of natural gas in heaters or compressor engines, the combustion of diesel fuel in crane engines or construction vehicles, the combustion of gas to produce electricity onsite and fugitive emissions from valves and connections, which include methane as a component.

Indirect emissions associated with a project include the emissions from vehicles (both gasoline and diesel) delivering materials and equipment to the proposed Project site or the use of electricity from the grid produced offsite. The production of electricity produces GHG emissions and needs to be accounted for as part of a project.

In order to quantify the emissions associated with electrical generation, the "resource mix" for a particular area must be determined. The resource mix is the proportion of electricity that is generated from different sources. Electricity generated from coal or oil combustion produces greater GHG emissions than electricity generated from natural gas combustion due to coal and oil's higher carbon content. Electricity generated from wind turbines, hydroelectric dams or nuclear power is assigned zero GHG emissions. Although these sources have some GHG emissions associated with the manufacture of the wind generators, the mining and enrichment of uranium or the displacement of forest areas for reservoirs, these emissions have not been included in the lifecycle analysis as they are assumed to be relatively small compared to the electricity generated. Estimates of nuclear power GHG emissions associated with uranium mining and enrichment range up to about 60 lbs/MWh, or about five percent of natural gas turbine GHG emissions (Canada 1998).

Detailed information on the power generation plants, their contribution to area electricity "resource mix" and their associated emissions have been developed by the Federal EPA in a database called the Emissions & Generation Resource Integrated Database (eGRID). The most recent version of eGRID (eGRID 2006), released in April 2007, was used in this analysis. eGRID is a comprehensive inventory of environmental attributes of electric power systems and is developed from a variety of data collected by the U.S. Environmental Protection Agency (EPA), Energy Information Administration (EIA), and Federal Energy Regulatory Commission (FERC).

eGRID includes electricity generated from coal, gas, oil, biomass (including wood, paper, agricultural byproducts, landfill gas, digester gas, etc), nuclear, hydroelectric, geothermal, solar, wind, and other fossil fuels (solid waste, tire derived fuel, hydrogen, methanol, coke gas, etc). Each of these is assigned criteria as well as GHG emission levels based on plant specifics. Nuclear, hydroelectric, wind, geothermal, biomass and solar are assigned zero GHG emissions. The eGRID assigns zero CO_2 emissions to generation from the combustion of all biomass because these organic materials would otherwise release CO_2 (or other greenhouse gases) to the atmosphere through natural decomposition. The other fuels are assigned GHG emissions levels based on the fuel carbon content.

An analysis of the database was conducted for this report in order to assign a GHG emissions level to electricity generated for the current and proposed Project operations. The resource mix and estimated GHG emissions for a range of areas is shown in the table below. Note that about half of the electricity in the United States is generated from coal, producing a U.S. GHG emissions level of about 1,363 lbs/MWh (pounds per mega-watt hour). The GHG emissions rate is lower for western states, primarily due to the increased use of hydroelectric and natural gas. The California Independent Service Operator (CALISO) area (which includes some generation outside of California) has a low GHG emission rate of about 687 lbs/MWh due to the contribution of hydroelectric, nuclear and renewable sources. See Table 4.3-5.

Table 4.3-5
Electricity Generation Resource Mix and GHG Emissions

Area	United States	Western States (WECC)	California ISO	So Cal Edison Service Area*
Resource Mix, percent				
Coal	50.2	34.2	1.2	1.7
Oil	3.0	0.5	1.2	0.9
Gas	17.4	26.3	51.1	41.9
Nuclear	20.0	9.9	16.8	38.0
Hydro	6.6	24.3	17.3	4.7
Biomass	1.4	1.3	3.2	2.9
Wind	0.3	0.9	2.4	3.8
Solar	0.0	0.1	0.3	0.8
Geo	0.3	2.0	5.5	4.1
Other Fossil	0.5	0.3	0.9	1.2
Other	0.1	0.0	0.0	0.0
Non-renewables	91.3	71.3	71.3	83.7
Renewables	8.7	28.7	28.7	16.3
Non-hydro Renewables	2.1	4.3	11.4	11.6
CO_2 Rate, lb/MWh	1363	1107	687	613

Notes:
*SCE Service area includes 75 percent of San Onofre, Geothermal in Nevada and hydro in Sierra Nevada, San Bernardino & LA.
Mojave Coal Fired Power Plant not included in CALISO or SCE service area.
Resource mix is the percentage of total mega-watt hours.
Non-hydro renewables include geo, solar, wind and biomass. Non-hydro renewables are a subset of the renewables category.
Source: eGRID 2006.

The Southern California Edison (SCE) GHG emission rate is lower than the CALISO average due to the reliance on the San Onofre nuclear power plant. The SCE service area includes partial use of electricity from the San Onofre nuclear power plant, the use of hydroelectric in San Bernardino and the Sierra Nevada and the use of geothermal plants located in Nevada. It was also assumed that the Mojave Coal power station is not in operation.

The GHG emission rate for electricity obtained from CALISO is about 45 percent less than the rate associated with direct natural gas combustion due to the electricity resource mix including non-GHG emission creating resources (hydroelectric, nuclear, renewables). This is based on the analysis of the eGRID database (eGRID 2006).

Crude Oil Transportation/Refining Lifecycle and GHG Emissions

One aspect of the "lifecycle" analysis of GHG emissions associated with the baseline and proposed Project is the dynamics of the crude oil markets in California. The supply of crude oil is driven by the demand for refined products (gasoline, diesel and jet fuel). Currently, the demand for refined products is met through supply to California refineries of crude oil from California domestic production, foreign imports of crude oil, imports of crude oil from Alaska, and imports of refined products. Minimal crude oil exports from California occurred in the late 1990s (less than one percent of California use) and very minimal crude oil has been exported from California since 2000 (less than 0.01 percent, EIA 2007). There are no crude oil pipelines, which bring crude oil into California. This means that the only sources of crude oil to meet refinery crude oil demand are from California production, Alaska production or from foreign sources brought into ports by tanker ships.

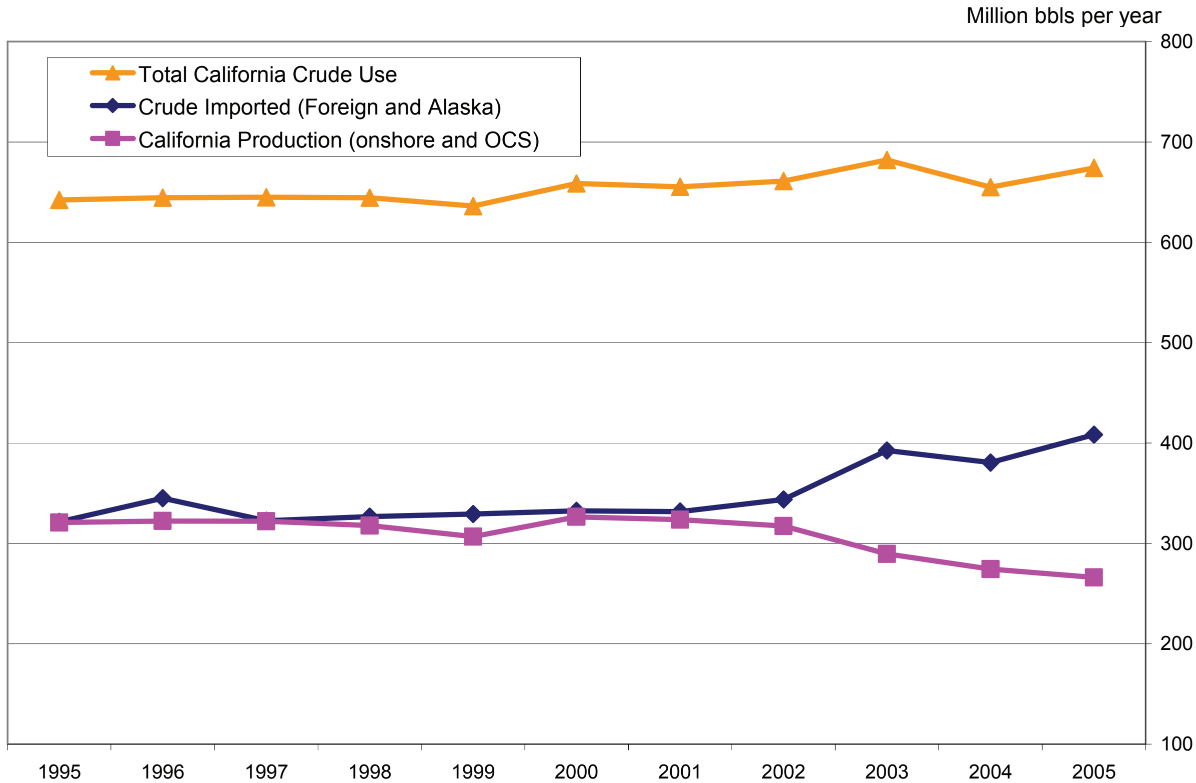
California production of crude oil has been in decline since 1986, when production peaked at slightly over 400 million barrels. The decline has averaged about 1.7 percent per year since 1995. More recently, the decline has averaged over three percent annually since the year 2000. Figure 4.3-2 shows the total California crude oil use, California production and the associated imports through California ports.

The production of Alaska North Slope (ANS) crude oil has experienced decline due to the age of the reservoirs. ANS production has declined since its peak in 1989 of about 328 million barrels annually. The average rate of decline since 1995 has been above four percent.

At the same time that there has been declining California production and declining ANS production, demand for crude oil in California has remained relatively flat, with an annual average increase since 1995 of only about 0.5 percent.

The combination of declining California and ANS production along with a relatively constant, flat demand for crude oil in California equates to an increase in foreign crude oil imports. Foreign crude oil imports since 1995 have increased by an average of almost 38 percent. As seen in Figure 4.3-2, the increase in imports closely mirrors the decline in California production since about 2000.

Figure 4.3-2
California Crude Oil Use, Production and Imports



Source: CEC and DOGGR databases online

The California Energy Commission has produced a number of reports on the State of the California crude oil markets. These reports present the following conclusions:

- "Declining domestic oil production will need to be replaced with increased imports of crude oil from foreign sources" (CEC 2007);
- "Declining California production will be replaced with crude oil delivered by marine vessel" (CEC 2003);
- A "reduction in [gasoline] use with alternative fuels and efficiency improvements will reduce imports of [refined] products, not imports of crude oil" (CEC 2007);
- "Without increasing the fuel supply by importing additional crude oil and transportation fuels, California will not only continue to experience supply disruptions and price spikes, but also supply shortages and prolonged and elevated prices, for gasoline fuels" (CEC 2003b); and

- "Supplies of crude oil from within California and from Alaska have been declining, requiring California to import an increasing proportion of its crude oil from foreign sources" (CEC 2003b).

The CEC estimates that increases in imports of crude oil to California translates into "an additional 150 shipments of crude oil [into ports] received per year [by] 2015" (CEC 2005).

A component of the crude oil markets involve Los Angeles area refineries and their associated ability to process a range of different crude oil types, from the relatively sweet/light ANS crude oil to the heavy San Joaquin Valley crude oil. Increased installation of cracking units at refineries in the last five to 10 years has increased the ability of refineries to process heavier crude oils as the supply of ANS crude oil and San Joaquin Valley light crude oil has diminished (SCAQMD CEQA Documents).

The three major regions of California crude oil production are Kern county, the Los Angeles Basin, and the Outer Continental Shelf (OCS). Kern county oil accounts for two-thirds of California total crude oil production. Approximately 58 percent of the Kern county crude oil has an API of 18 degrees or less (heavy crude oil). The Los Angeles Basin's largest fields are the Wilmington and the Huntington Beach fields, with average APIs of 17 degrees to 19 degrees, respectively (heavy crude oil). The OCS accounts for about 10 percent of the total California production. The quality of OCS crude oil varies by field with API gravities ranging from 14 degrees to 38 degrees (heavy to light crude oil) (CEC 2006).

ANS crude oil ranges from an API gravity of 22 degrees to 40 degrees (light crude oil).

Oil imports delivered to California from foreign sources by ocean going tankers come from Saudi Arabia (35 percent), Ecuador (25 percent), Iraq (12 percent), Mexico (seven percent) and others. The Saudi crude oil API gravity ranges from 28 degrees to 34 degrees (light crude oil) (CEC 2006).

The use of foreign crude oil is associated with emissions associated with transportation as foreign crude oil needs to be transported via tanker from between 4,000 miles (Ecuador, 6,400 km) and 13,000 miles (Saudi Arabia, 22,000 km) one-way to get to California. ANS crude travels about 2,500 miles (4,200 km) from Alaska. This causes the GHG lifecycle emissions associated with tankering foreign crude oil, at least from Saudi Arabia, to be substantially higher than California crude oil.

Transportation of California crude oil requires energy to pump the crude oil to the refineries. This energy is generally a function of the type of crude oil, if heating is required and the distance and terrain between the wells and the refinery.

Very little, if any, crude oil is exported from California. Since the beginning of 2001 through the end of November 2007, 1,367,000 barrels of crude has been exported from Petroleum Administration for Defense District 5 (PADD) (California, Arizona, Nevada, Oregon, Washington, Alaska, and Hawaii). The majority of the exports were a shipment to China of 805,000 barrels in April 2004, 401,000 barrels to Canada in January 2006, and 57,000 barrels to Canada in October 2004 (EIA 2008). The remaining exports from PADD 5 (17 shipments) were to Canada and Mexico, and averaged approximately 6,000 barrels per shipment. Given the small size of most of these shipments, it is likely they were via truck and not marine tanker.

Refining of crude oil into end-use products, such as gasoline, diesel and jet fuel, requires energy. Refinery energy requirements are a function of the refinery arrangements, the type of crude oil, the type of gasoline being produced (winter or summer blends), the level of sulfur removal required, etc. Efficiencies of refineries have been shown to range from 83 to 87 percent (GM, 2001), meaning that 13 to 17 percent of the product energy content is required to refine the product.

Regional Emissions

Emissions of ROC and NO_x within the county were estimated by the Santa Barbara County Air Pollution Control District (SBCAPCD) in the 2004 Updates to the Clean Air Plan (Table 4.3-6, also shows 1998 county total emissions of CO, SO_2 and PM_{10}, but these emissions no longer are included in the Clean Air Plan Emission Inventories). These estimates are used to address Federal and State clean air mandates. The highest contributors to the ROC emissions are natural sources, primarily natural uncontrolled seeps of oil and gas constituents through cracks and voids in the ground. Emissions of CO and NO_x mostly occur due to mobile sources (e.g., on-road vehicles). The majority of SO_x emissions in the county come from mineral processes, specifically from diatomaceous earth processing. Particulate emissions sources vary from dust caused by agricultural and construction activities, on-road dust, various mineral processing, to particulate emissions from combustion engines.

Table 4.3-6
Emission Inventory for Santa Barbara County

Emission Sources [10]	CO [10] tons/yr	ROC tons/yr	NO_x tons/yr	SO_2 [10] tons/yr	PM_{10} [10] tons/yr
Stationary	1,551	3,666	2,096	552	554
Area-Wide	9,433	3,064	350	8	10,584
Mobile	82,532	8,687	13,803	305	572
Natural	11,404	28,930	1,364	0	1,843
All Sources	103,369	44,348	17,615	865	13,553

Notes:
mt/yr = metric tons per year
[10] SBCAPCD 1998
Source: SBCAPCD 2004.

Current Facilities Permits and Emissions

The air quality baseline for the proposed Project includes existing emissions from both the permitted and exempt equipment at the Project facilities, including the Ellwood Onshore Facility (EOF), Platform Holly, Ellwood Marine Terminal (EMT), marine vessels associated with the EMT, and the equipment on the Barge *Jovalan*. The permitted emissions for these facilities, including mobile sources such as the tug and assist vessels that are required to move the Barge *Jovalan*, are covered under the appropriate SBCAPCD Permits to Operate (PTOs): PTO No. 7904-R7 for EOF, PTO No. 8234-R6 for Platform Holly, PTO No. 8232-R6 for the EMT and vessels, and PTO No. 8233-R6 for the Barge *Jovalan*. Table 4.3-7 identifies the categories of the equipment emission sources at the current facilities.

Table 4.3-8 summarizes the current emissions from the facilities. These are the facility emissions reported annually to the SBCAPCD, which are calculated based on the number of connectors, equipment hours of operation, and fuel consumed. Pollutant emissions that make up the air quality baseline are currently below the permitted limits.

The EOF provides ROC emission reduction credits (ERCs) to the Point Arguello Project of 101.2 tons/year.

Table 4.3-7
Current Facilities Emission Sources

<table>
<tr><th>EOF</th><th>PLATFORM HOLLY</th></tr>
<tr><td>Permitted Equipment and Emissions:
- ROC, NO_x, CO, PM_{10} and SO_2 from three gas-fired external combustion (EC) engines on three Heater Treaters;
- ROC, NOx, CO, PM10 and SO_2 from an EC engine a process heater fueled by in-plant fuel gas plus permeate gas;
- ROC, NO_x, CO, PM10 and SO_2 from three gas-fired EC engines on thermal oxidizers;
- ROC, NOx, CO, PM10 and SO_2 from diesel-driven backup emergency generator;
- Fugitive ROC emissions from two storage tanks, one emulsion breaker tank, one oil pig receiver, one gas pig receiver, one gas pipeline launcher, one utility gas receiver, one process sump; one wash tank, LPG/NGL loading rack, a rack to handle emulsion breaker liquid, one diesel fuel pump with nozzle, and various valves, connectors, seals and pressure relief devices.
- ROC, NOx, CO, PM10 and SO_2 from diesel-driven emergency firewater pump and generator.</td><td>Permitted Equipment and Emissions:
- ROC, NO_x, CO, PM_{10} and SO_2 from combustion flare;
- ROC, NO_x, CO, PM_{10} and SO_2 from diesel-fueled supply and crew boats, and boom boat;
- Fugitive ROC emissions from pigging equipment, sumps, tanks and separators, various valves, and connectors.

Permit-Exempt Equipment:
- ROC, NO_x, CO, PM_{10} and SO_2 from drilling equipment: crane, electric line unit, slick line unit hydraulic line unit, coiled tubing unit, power generators Nos. 1, 2, and 3, cement unit, compressor, nitrogen unit – combined drilling equipment emissions should not exceed 25 tons/year of any criteria pollutant;
- ROC from solvent and coating use.</td></tr>
<tr><th>EMT AND VESSELS</th><th>BARGE JOVALAN</th></tr>
<tr><td>Permitted Equipment and Emissions:
- Fugitive ROC from the two oil storage tanks;
- Fugitive ROC from piping components and pump seals;
- ROC, NO_x, CO, PM_{10} and SO_2 from diesel tug vessel main and auxiliary engines, and generator engine;
- ROC, NO_x, CO, PM_{10} and SO_2 from diesel assist vessel main engine, and generator engine;
- ROC, NO_x, CO, PM_{10} and SO_2 from emergency response vessel diesel engine.

Permit-Exempt Equipment:
- None</td><td>Permitted Equipment and Emissions:
- ROC, NO_x, CO, PM_{10} and SO_2 from three Vapor Recovery Unit (VRU) Internal combustion (IC) diesel engines exhaust products;
- ROC emissions displaced during filling of the Barge Jovalan “holds” (tanks) with crude oil;
- Fugitive hydrocarbons from various piping and pressure relief device components;
- Fugitive emissions from sump;
- ROC, NO_x, CO, PM_{10} and SO_2 from diesel-fired IC engine with 89 brake-horsepower rating.

Permit-Exempt Equipment:
- None</td></tr>
</table>

Table 4.3-8
Facilities Current and Permitted Emissions

Facility	NO_x tons/yr	ROC tons/yr	CO tons/yr	SO_2 tons/yr	PM_{10} tons/yr
Current (2005) Emissions					
EOF	10	97	64	5.2	1.8
Platform Holly, Operations	4.4	29	3.5	0.8	0.4
Platform Holly, Drilling	2.6	1.1	3.3	0.2	0.6
Crew and Supply Boats	70	2.7	10	7.0	4.0
EMT and Vessels	5.0	25	0.6	0.1	0.3
Barge *Jovalan*	1.8	2.7	0.5	0.0	0.1
Total	***93***	***157***	***82***	***13***	***7***
Permitted Emissions					
EOF, PTO No. 7904-R7	23.96	79.06	106.83	9.41	2.32
Platform Holly, PTO No. 8234-R6	184.45	35.60	31.74	18.41	10.83
EMT and Vessels, PTO No. 8232-R6	131.27	10.63	14.51	1.62	7.75
Barge *Jovalan*, PTO No. 8233-R6	8.94	8.83	2.51	0.13	0.69
Total Permitted	**348.62**	**134.12**	**155.59**	**29.57**	**21.60**

Notes:
Totals may not add up due to rounding.
1 ton = 0.9 metric ton; 1 pound (lb) = 0.45 kilogram (kg)
Sources: SBCAPCD 2006a; SBCAPCD 2006b, SBCAPCD 2005a, SBCAPCD 2005b, SBCAPCD 2005c

The Project facilities PTOs also specify maintenance, reporting, and record keeping requirements imposed by the SBCAPCD. Some of the more important requirements include:

- Conduct inspections for fugitive hydrocarbon leaks, record any leaks, repairs and re-inspections;
- Report to the SBCAPCD non-compliance with the facility permit, or any SBCAPCD Rule or regulation;
- Report to the SBCAPCD any breakdowns, with any excess emissions associated with the breakdowns; and
- Assist the SBCAPCD in investigating any alleged nuisance odor complaints.

In accordance with PTO 8232-R6, Venoco funds an ambient air monitoring station approved and maintained by the SBCAPCD located at Coal Oil Point. The station monitors the following parameters: ambient air concentrations of total hydrocarbons,

H_2S, SO_2 and total reduced sulfur, wind speed and direction, wind variation, and ambient temperature.

To control odorous and ROC emissions, the Barge *Jovalan* has a Vapor Recovery Unit (VRU) that includes a caustic H_2S scrubber system and a refrigeration hydrocarbon removal system. The VRU is designed to collect and control the headspace vapors produced during crude oil loading as vapor in the barge holds is displaced by oil.

In the Federal ozone standard attainment area (such as Santa Barbara county), only those sources with the Federal potential to emit (PTE) of 100 tons/year (91 metric tons/year) or more require a Part 70 Federal permit. Currently, the Federal NO_x PTE for the EMT stationary source (includes EMT, vessels, and sources associated with the Barge *Jovalan*) is greater than 100 tons/year (91 metric tons/year) emissions; thus, the EMT remains a major stationary source. However, the EMT stationary source is exempt, based on SBCAPCD Rule 370, from Part 70 permitting requirements due to its "actual" emissions, as opposed to "potential" emissions. Rule 370 requires a demonstration of a stationary source's "actual" emissions being less than 50 tons/year (45 metric tons/year).

Currently, neither the EMT nor the Barge *Jovalan* provide emission reduction credits[11] (ERCs) to other emission sources. These facilities do not require any ERCs to operate.

Health Risk Associated with the Project Facilities

The facilities emit HAPs due to a number of different processes, including fugitive emissions from valves, connections and tanks, combustion of natural gas in heaters and combustion of diesel fuel in engines, including boats, cranes, and generators. The total emissions of HAPs estimated for the year 2005 are shown in Appendix E, Air Quality. The largest amount of pollutants emitted include hydrogen sulfide and benzene from fugitive emissions, diesel exhaust particulates and formaldehyde from boats and drilling engines, hexane and 1,2,4-trimethylbenzene from the crude oil storage tanks and naphthalene from the heaters.

California State law requires facilities that emit HAPs to conduct a health risk assessment. The term "health risk" addresses the likelihood that exposure to a given

[11] An Emission Reduction Credit (ERC) is an actual emission reduction of specific type and quantity that is registered with the SBCAPCD in accordance with Rule 806. The ERC certificate is a document that represents emission reduction credits registered in the Source Register. The certificate is initially issued by the SBCAPCD to a source that qualifies its actual emission reductions for registration in the Source Register by meeting the requirements of Rule 806. The certificate is transferable.

toxic air contaminant under a given set of conditions will result in an adverse health effect. Health risk is affected by several factors, such as: the amount, toxicity, and concentration of the contaminant; the meteorological conditions; the distance from emission sources to people; the distance between emission sources; the age, health, and lifestyle of the people living or working at a location; and, the duration of exposure to the toxic air contaminant.

Health effects are divided into cancer and non-cancer risks. "Cancer risk" refers to the increased chance of contracting cancer as a result of an exposure, and is expressed as a probability: chances-in-a-million.

For non-cancer health effects, risk is characterized by a "Hazard Index" (HI), which is obtained by dividing the predicted concentration of a toxic air contaminant by a Reference Exposure Level (REL) for that pollutant that has been determined by health professionals, the Office of Environmental Health Hazard Assessment (OEHHA), and the CARB. RELs are used as indicators of the potential adverse effects of chemicals. A REL is the concentration at or below which no adverse health effects are anticipated for specific exposure duration.

The most recent HRA for the EOF conducted in accordance with AB 2588, was completed in 2003 using the 2001 toxic emissions inventory. The most recent HRA for Platform Holly conducted in accordance with AB 2588, was completed in 1993 using 1991 toxic emissions inventory. The most recent Health Risk Assessment (HRA) for the EMT, conducted in accordance with AB 2588, was completed in 1994 using 1991 air emissions data. Since the time when these HRAs were conducted for the Project facilities, several changes to equipment have occurred. Therefore, a revised baseline analysis was conducted for this EIR which combined all of the HRA for the EOF, Holly and the EMT and updated some of the operating parameters.

Table 4.3-9 summarizes the historical results of HRA analysis on the EOF, EMT and Platform Holly. The revised baseline HRA also includes emissions from supply boats that utilize Ellwood Pier. Previous HRAs only included a supply boat at Platform Holly since the supply boats originated from Port Hueneme and did not utilize Ellwood Pier.

Although cancer risk for the EOF in the 2002 HRA was estimated above the SBCAPCD threshold, the SBCAPCD did not consider the 2002 HRA impacts significant because it occurs within a facility easement, to which there is no public access.

Table 4.3-9
Current Facilities Historical HRA Results

Facility	Emissions Year (Analysis Year)	Cancer Risk per million (Threshold = 10 per million)	Non Cancer Risk Index	
			Chronic (Threshold = 1)	Acute (Threshold = 1)
EMT	1991 (1994)	0.40 (not significant)	0.00 (not significant)	0.90 (not significant)
	2003 (2005)	2.51 (not significant)	0.0019 (not significant)	0.412 (not significant)
EOF	1998 (1999)	90.06 (significant)	1.97 (significant)	21.96 (significant)
	2002 (2003)	23.6 (significant)	0.05 (not significant)	0.96 (not significant)
Pl. Holly	1991 (1993)	8.0 (not significant)	0.04 (not significant)	6.0 (significant)
EMT, EOF and Holly	Revised Baseline	32.1 (significant)	0.10 (not significant)	1.13 (significant)

Sources: For the HRA results include SBCAPCD 1994, SBCAPCD 2005a, and SBCAPCD 2005b.

The revised baseline HRA shows a cancer risk above the historical estimates for the EOF. This is due to the combined effect of the EOF equipment and the crew and supply boat emissions. The cancer risk is primarily due to particulate matter emissions from diesel engines. Diesel exhaust is emitted from diesel internal combustion engines at the EOF (engines for the air compressor, emergency firewater pump, and emergency generator) and crew and supply boats associated with Platform Holly.

Platform Holly cancer risk and chronic HI have been below the significance thresholds; the acute HI is above the significance threshold of one.

All health risk factors for the EMT have been below the significance thresholds.

The analysis used the same Hot Spots Analysis and Reporting Program (HARP) model and the meteorological conditions, emission factors, and emission sources' parameters, e.g., stack dimensions, gas velocities, exhaust temperatures, equipment coordinates, etc., as were used in the most recent historical HRA for each facility, where possible.

The revised HRA reflects the following:

- EOF, EMT, and Platform Holly equipment are accounted for in the same modeling runs of the revised HRA, including the boats that support the platform's operations;
- HAPs emissions from supply and crew boats that service Platform Holly utilize a diesel PM factor to reflect the current CARB requirements for HAP emissions from diesel engines;

- The use of diesel additives for stationary diesel fueled engines at the EOF;
- Supply boats increased use of Ellwood Pier instead of Port Hueneme, as per annual emission reports to the SBCAPCD; and
- Inclusion of Platform Holly drilling engine activities.

The results of the revised baseline HRA (shown in Table 4.3-9) indicate risks are higher than the historical HRAs due to diesel engines at the EOF and the inclusion of additional supply boat traffic originating at the nearby Ellwood Pier. The results indicate that the health risk from the combined Venoco Ellwood Facilities would exceed applicable SBCAPCD thresholds and would be considered significant, requiring risk reduction measures.

Odor Complaints associated with the Project Facilities

The SBCAPCD conducts investigations to determine if odor complaints are associated with the facilities under the SBCAPCD jurisdiction. It is the policy of the SBCAPCD to conduct an investigation for each odor complaint received.

The EOF, EMT, and Platform Holly facilities historically have produced odors, which have generated complaints from the public. Odor complaints associated with the EMT, EOF, and Platform Holly facilities have been documented by the SBCAPCD and by the Santa Barbara County Fire Department (2000). Due to a series of odor complaints in the late 1990's, the SBCAPCD issued Abatement Order No. 99-6(A) on April 14, 1999. The Abatement Order included measures that targeted reduction and elimination of nuisance odors from the facilities. Since 1999, odor complaints have been reduced.

From the period August 2003 to April 2005, there was a series of confirmed odor complaints attributed to the EMT operations, which was due to leaks in the EMT oil storage tanks internal floating roof. Corrosion created holes in the roofs of both tanks, so that oil leaked out and created puddles on the top of the internal floating roofs. The odors were confirmed by the SBCAPCD inspectors.

The tanks were drained, inspected internally for corrosion, and repairs to both tanks were initiated. During the work on the tanks, the SBCAPCD received and confirmed more nuisance odor complaints. The SBCAPCD determined that the source of the odors were hydrocarbon based solvents, used to clean the internal surfaces of the tanks during the repair activities. Both tanks have been repaired and are back in service.

After the tanks were repaired, there have been no consistent odor complaints related to the EMT.

There have been two occurrences of odor complaints associated with EOF operations in 2007. One complaint occurred on October 29, 2007, and the exact source of the release was not confirmed, although a low-level H_2S alarm near the edge of the Applicant's property line was triggered. The other complaint occurred on November 14, 2007, and was attributed to gas released from a wash tank (T-201) and an oil shipping tank (T-202).

Some odor complaints received by the SBCAPCD are attributed to natural gas seeps present in the vicinity of Platform Holly and the Barge *Jovalan* mooring location. Natural gas seeps are a documented phenomenon that is due to the leaking of oil and gas from the sea-floor. The Applicant operates two seep tents located approximately one mile (1.6 km) southeast of Platform Holly. The seeping gas and oil bubble up from the ocean floor and are captured by the seep tents. The tents were designed specifically to minimize air and water pollution and collect the naturally seeping gas and oil. Natural seeps occur in other locations, where they are not captured but escape into the atmosphere, and create odors if odorous mercaptans and H_2S are present in the gas.

Greenhouse Gas Emissions

Greenhouse gas (GHG) emissions are calculated for both direct and indirect emissions. In 2005, the Project facilities emitted greenhouse gases in the amounts summarized in Table 4.3-10. Direct emissions included fuel combustion (at the 2005 reported levels) and fugitive emissions. Indirect emissions are associated with vehicles (employee commuters and truck trips) and emissions associated with offsite electrical generation (purchased from the grid) to produce the electricity used by the EOF and Platform Holly. GHG emissions rates from electrical generation, due to the wide variability in electricity sources and between seasons and times of day, used the CALISO rate discussed above. GHG emissions associated with the transportation of the crude oil to Los Angeles were also included.

4.3.2 Regulatory Setting

Federal, State, and local agencies have established standards and regulations that govern the proposed Project. A summary of the regulatory setting for air quality is provided below.

Table 4.3-10
Current Greenhouse Gases Emissions Summary

Emission Source	Annual Emissions (tons/yr)	
	CO_2	CH_4
Direct Emissions		
EOF		
Combustion (HT-201 thru HT-204)	10,163	0.12
Combustion – flares (H-205 thru H-207)	11,577	0.24
Fugitives	0	8.91
Other	8	0.00
Platform Holly	-	-
Combustion (drilling engines and generators)	1,525	0.03
Combustion - flare	785	0.02
Crew and Supply Boats	2,773	0.00
Fugitives	0	3.05
Others	156	0.00
EMT (tug, assist and ER boats)	198	3.00
Barge at Ellwood	85	0.31
Barge Transport to LA/SF	6,673	0.00
Total Direct Emissions	**33,943**	**16**
Indirect Emissions		
Electrical Generation	18,852	0
Offsite Vehicles	496	0
Total Indirect Emissions	**19,347**	**0**
Total GHG Emissions	**53,291**	**16**
Total CO_2-e, tons/year	**53,620**	
Total CO_2-e, metric tonnes/year	**48,745**	

Notes:
CO_2-e = carbon dioxide equivalent
Electrical generation assumes CALISO weighted average GHG emission rate.
Using 2005 AER information as submitted to the SBCAPCD.

Federal

The Federal Clean Air Act of 1970 directs the attainment and maintenance of the NAAQS. The 1990 Amendments to this Act included new provisions that address air pollutant emissions that affect local, regional, and global air quality. The main elements of the 1990 Clean Air Act Amendments are summarized below:

- Title I   Attainment and maintenance of NAAQS;

- Title II Motor vehicles and fuel reformulation;
- Title III Hazardous air pollutants;
- Title IV Acid deposition;
- Title V Facility operating permits (describes requirements for Part 70 permits);
- Title VI Stratospheric ozone protection; and
- Title VII Enforcement.

The U.S. EPA is responsible for implementing the Federal Clean Air Act and establishing the NAAQS for criteria pollutants. In 1997, the EPA adopted revisions to the Ozone and Particulate Matter Standards contained in the Clean Air Act. These revisions included a new 8-hour ozone standard and a new particulate matter standard for particles below 2.5 microns in diameter. These standards were suspended, however, when in May 1999, the U.S. Court of Appeals for the District of Columbia remanded the new ozone standard. In January 2001, the EPA issued a Proposed Response to Remand, in which it stated that the revised ozone standard should remain at 0.08 ppm. In February 2001, the U.S. Supreme Court upheld the constitutionality of the Clean Air Act as the EPA had interpreted it in setting health-protective air quality standards for ground-level ozone and particulate matter. In April 2004, the EPA issued their Final Non-Attainment Area Designations for 8-Hour Ozone Standard.

State

California Air Resources Board (CARB).

The CARB established the CAAQS. Comparison of the criteria pollutant concentrations in ambient air to the CAAQS determines State attainment status for criteria pollutants in a given region. CARB has jurisdiction over all air pollutant sources in the State; it has delegated to local air districts the responsibility for stationary sources and has retained authority over emissions from mobile sources. CARB, in partnership with the local air quality management districts within California, has developed a pollutant monitoring network to aid attainment of CAAQS. The network consists of numerous monitoring stations located throughout California that monitor and report various pollutants' concentrations in ambient air.

California Clean Air Act (CCAA) (California Health and Safety Code, Division 26).

This act went into effect on January 1, 1989, and was amended in 1992. The CCAA mandates achieving the health-based CAAQS at the earliest practical date.

Air Toxics "Hot Spots" Information and Assessment Act of 1987 (California Health & Safety Code, Division 26, Part 6).

The Hot Spots Act requires an inventory of air toxics emissions from individual facilities, an assessment of health risk, and notification of potential significant health risk.

California Health & Safety Code sections 25531–25543, The Calderon Bill (SB 1889).

These sections set forth changes in the following four areas: (1) provides guidelines to identify a more realistic health risk; (2) requires high-risk facilities to submit an air toxic emission reduction plan; (3) holds air pollution control districts accountable for ensuring that the plans will achieve their objectives; and (4) requires high-risk facilities to achieve their planned emission reductions.

California Global Warming Solutions Act of 2006 (AB 32).

The Global Warming Solutions Act caps California's greenhouse gas emissions at 1990 levels by 2020. This legislation represents the first enforceable State-wide program in the U.S. to cap all GHG emissions from major industries that includes penalties for non-compliance. It requires the CARB to establish a program for State-wide greenhouse gas emissions reporting and to monitor and enforce compliance with this program. The Act authorizes the CARB to adopt market-based compliance mechanisms including cap-and-trade, and allows a one-year extension of the targets under extraordinary circumstances.

The regulatory steps laid out in AB 32 require CARB to: adopt early action measures to reduce GHGs; establish a State-wide greenhouse gas emissions cap for 2020 based on 1990 emissions; adopt mandatory reporting rules for significant source of greenhouse gases; and adopt a scoping plan indicating how emission reductions will be achieved via regulations, market mechanisms and other actions; and adopt the regulations needed to achieve the maximum technologically feasible and cost-effective reductions in greenhouse gases.

In June 2007, CARB adopted three discrete early action measures which include the following: a low carbon fuel standard; reduction of HFC-134a emissions from non-professional servicing of motor vehicle air conditioning systems; and improved landfill methane capture. CARB estimates that by 2020 the reductions from those three discrete early action measures would be approximately 13 MMT to 26 MMT CO_2-e (CAPCOA 2008).

Local

Local Air Pollution Control Districts in California have jurisdiction over stationary sources in their respective areas and must adopt plans and regulations necessary to demonstrate attainment of Federal and State air quality standards. As directed by the Federal and State Clean Air Acts, local air districts are required to prepare plans with strategies for attaining and maintaining State and Federal ozone standards. In the Project area, air quality rules and regulations are promulgated by the SBCAPCD. In order to ultimately achieve the air quality standards, the rules and regulations limit emissions and permissible impacts from the proposed Project. Some rules also specify emission controls and control technologies for each type of emitting source. The regulations also include requirements for obtaining an Authority To Construct (ATC) permit and a PTO.

Santa Barbara County Air Pollution Control District

The SBCAPCD has jurisdiction over air quality attainment in the Santa Barbara county portion of the SCCAB. All aspects of the proposed Project and Alternatives occurring in Santa Barbara county must obtain a SBCAPCD permit, if applicable. The SBCAPCD also has jurisdiction over Outer Continental Shelf (OCS) sources located within 25 miles (40 km) of the seaward boundaries of the State of California (Rule 903). Increases in emissions of any non-attainment pollutant or its pre-cursor from a new or modified project that exceed the thresholds which have been identified in the SBCAPCD Regulation VIII, are required to be mitigated. Other applicable rules are summarized below.

Rule 201, Permits Required – Specifies the permits required for construction or operation of equipment that emits air contaminants.

Rule 202, Exemptions to Rule 201 – Lists equipment categories that are exempt from the requirements to obtain an SBCAPCD permit (exempt from Rule 201).

Rule 303, Nuisance, and Rule 310 – Odorous Sulfates – These rules prohibit air emissions that cause a nuisance, e.g., odorous sulfates.

Regulation XIII – Defines criteria for Part 70 source applicability, and permit content and requirements for part 70 sources.

Rule 370, Potential to Emit - Limitations for Part 70 Sources – Specifies actual emission level criteria below which Part 70 sources are exempt from Part 70 permit requirements.

Rule 802, Non-Attainment Review – For new or modified emission sources, this rule specifies emission limits that would trigger emission offsets (80 lbs/day for PM_{10}, 55 lbs/day for any non-attainment pollutant and 150 lbs/day for carbon monoxide) or trigger Best Available Control Technology (BACT) requirements (25 lbs/day for any non-attainment pollutant and 150 lbs/day for carbon monoxide). Note that currently, the area is in non-attainment for NO_x, ROC, PM_{10} and SO_x (the latter as a particulate precursor).

The Goleta General Plan section 4.0, Conservation Element, Policy CE 12: Protection of Air Quality [GP] establishes as an objective "to maintain and promote a safe and healthy environment by protecting air quality and minimizing pollutant emissions from new development and from transportation sources." Policy CE 12.2 "Control of Air Emissions from New Development" states that any development proposal that has the potential to increase emissions of air pollutants shall be referred to the Santa Barbara County Air Pollution Control District for comments and recommended conditions prior to final action by the city and that all new commercial and industrial sources shall be required to use the best available air pollution control technology.

Policy CE 12.3 "Control of Emissions during Grading and Construction" directs that construction site emissions shall be controlled by using measures such as watering, covering trucks, paving or applying stabilizers on unpaved access roads, hydroseeding, enclosing or covering open material stockpiles, and re-vegetating graded areas.

4.3.3 Significance Criteria

Operational Thresholds

The operational air quality impacts of the proposed Project would be significant if the EOF or Platform Holly do not comply with the terms of the respective PTOs (PTO 7904-R7 and PTO 8234-R6) granted by the SBCAPCD. A proposed project will not have a significant air quality effect on the environment, if operation of the project will (Based on the Santa Barbara County CEQA Threshold Manual);

- Emit (from all project sources, mobile and stationary), less than the daily trigger for offsets set in the APCD New Source Review Rule, for any pollutant;
- Emit less than 25 pounds per day of oxides of nitrogen (NOx) or reactive organic compounds (ROC) from motor vehicle trips only;
- Not cause or contribute to a violation of any California or National Ambient Air Quality Standard (except ozone);
- Does not allow land uses that create objectionable odors or does not expose sensitive receptors to objectionable odors;
- Not exceed the APCD health risk public notification thresholds adopted by the APCD Board; and
- Be consistent with the adopted federal and state Air Quality Plans

Cumulative impacts would be deemed significant if the proposed Project in association with other projects results in an inability to meet state and federal standards.

Construction Thresholds

Emissions from construction activities are normally short-term. Currently, neither the county, nor city, nor the SBCAPCD have daily or quarterly quantifiable emission thresholds established for short-term construction emissions. PM_{10} impacts from dust emissions should be discussed and standard mitigation measures implemented, e.g., watering, as required in the 1979 Air Quality Attainment Plan (SBCAPCD 2005) and the County Environmental Thresholds and Guidelines Manual (County 2006). Quantitative thresholds of significance are not currently in place for short-term or construction emissions; however, construction projects with 25 tons per year for any pollutant, except CO, would be found significant by the SBCAPCD, and would trigger offsets per Rule 202. Emissions originating from the removal of facilities are subject to SBCAPCD permit requirements; however, offsets are prohibited by State law.

GHG Emission Thresholds

CAPCOA published a discussion paper (CAPCOA 2008) on CEQA and climate change which laid out three different approaches to establishing significance criteria for CEQA documents. These are;

- No significance thresholds;
- Significance thresholds set at zero; and
- Significance thresholds set at non-zero values, which are variations of ways to achieve the 2020 goals of AB 32.

The CAPCOA paper does not designate a preferred approach; it only lays out the different approaches that an agency might take.

In this EIR, the second approach has been utilized, such that;

- A project would be considered having a significant impact if its GHG emissions have a net increase over the baseline.

Because of the severity of the global warming problem as the result of cumulative GHG emissions worldwide, the zero-threshold approach appears to be the most scientifically supportable of the options.

4.3.4 Impact Analysis And Mitigation

Air quality impacts result from increased emissions associated with drilling of new wells, and continuing operation of the Project facilities at levels above current operations due to increased oil and gas throughput. Decreases in operational emissions are expected due to removal of the EMT and the use of pipeline transportation for crude oil instead of the barge loading operations and associated vessel emissions.

Impact AQ-1: Emissions from Construction

Proposed Project construction activities would result in emissions at the EOF, EMT, and along the new pipeline corridor (Potentially Significant, Class II).

Impact Discussion

Emissions would be produced due to construction machinery, commuter and construction support vehicles, and fugitive dust. These emissions were estimated and are summarized in Table 4.3-11. Construction emissions that exceed 25 tons in any consecutive 12 months would be required to be offset under Rule 202. Demolition emissions (i.e., EMT and barge mooring removal) are subject to SBCAPCD permit requirements, but offsets are not required as per California H&S Code.

Table 4.3-11
Proposed Project Construction Emissions

	Peak Day Emissions (lbs/day)					Annual Emissions (tons/yr)				
Construction Phase	**CO**	**ROC**	**NO_x**	**SO_2**	**PM_{10}**	**CO**	**ROC**	**NO_x**	**SO_2**	**PM_{10}**
EOF Construction	311	30	117	3	36	22.60	2.15	4.32	0.12	0.90
Pipeline Construction	996	71	393	8	52	76.86	5.53	24.42	0.51	3.98
Offshore Power Cable Installation	230	56	695	14	65	2.33	0.42	2.49	0.05	0.22
Platform Holly Modifications	164	33	314	6	29	6.46	0.90	7.36	0.15	0.68
EMT Demolition	548	53	317	7	78	16.28	2.24	11.46	0.23	1.02
EMT Soil Remediation	41	10	73	1	18	0.62	0.15	1.44	0.03	0.12
Total Emissions						125	11.3	50	1.1	6.8
Total Emissions w/o EMT						108	8.9	37	0.8	5.7
Significance Criteria						na	25	25	na	na

Notes:
Demolition Emissions would be exempt from the SBCAPCD rule requiring offsets.
Construction phases would not affect the same peak day. However some phases would occur during the same 12-month period.

Section 42301.13 of California Health and Safety Code states that a district shall not require any form of emission offset or emission credit to be provided to offset emissions resulting from any activity related to the demolition or removal of a stationary source. Therefore, no emission offsets would be required for demolition/removal of the EMT and mooring.

Project construction ROC emissions would be below the Rule 202 trigger of 25 tons/year. Project construction NO_x emissions that would be emitted in the 12-month construction period for the changes at the EOF, pipeline construction, and offshore changes (Platform Holly retrofits, power cable installation and repairs to the two-inch (0.05 m) utility line would exceed 25 tons. And therefore, as per the Rules 202 and 804, the SBCAPCD would consider this impact significant and require emission offsets for the total emissions from the construction equipment not exempt under the Rule 202.

The emissions from EMT removal are above the SBCAPCD thresholds for construction and would normally require offsets as a construction project. However, Rule 202 provides an exemption for emissions from facility removal activities. As such, emissions from the removal of the EMT and barge mooring, and EMT soil remediation would be exempt under Rule 202. Without counting emissions from these exempt activities, the NO_x emissions would be equal to 37 tons/year.

PM_{10} emissions associated with construction would require the implementation of dust control measures detailed in the Air Quality Attainment Plan (SBCAPCD 2005) and the County Environmental Thresholds and Guidelines Manual (County 2006). Dust control measures are required under the County of Santa Barbara's Grading Ordinance for most projects.

Mitigation Measures

Because the county is a non-attainment area for PM_{10}, standard fugitive dust reduction measures are required for all earth-moving projects.

AQ-1a. Measures to Reduce Dust Emissions From Construction. Best Available Control Measures (BACMs) shall be implemented to control PM_{10} generation during construction of the Project, including the following:

- During construction, water trucks or sprinkler systems should be used to keep all areas of vehicle movement damp enough to prevent dust from leaving the site. At a minimum, this should include wetting down such areas in the late morning and after work is completed for the day. Increased watering frequency shall be required whenever the wind speed exceeds 15 mph. Reclaimed water shall be used whenever possible;

- Minimize the amount of disturbed area and reduce onsite vehicle speeds to 15 mph or less;

- Gravel pads shall be installed at all access points to prevent tracking of mud on to public roads;

- If importation, exportation, and stockpiling of fill material is involved, soil stockpiled for more than two days shall be covered, kept moist or treated with soil binders to prevent dust generation. Trucks transporting fill material to and from the Project site shall be covered with a tarp from the point of origin;

- After clearing, grading, earthmoving, or excavation is completed, the disturbed area shall be treated by watering, re-vegetating, or spreading of soil binders, until the area is paved or otherwise developed so that dust generation will not occur;
- The contractor or builder shall designate a person or persons to monitor the dust control program and to order increased watering, as necessary, to prevent transport of dust off site. Their duties shall include holiday and weekend periods when work may not be in progress. The name and telephone number of such persons shall be provided to the SBCAPCD prior to land use clearance for any grading activities for the Project; and
- Prior to any land clearance, the Applicant shall include, as a note on a separate informational sheet to be recorded using a map, these dust control requirements. All requirements shall be shown on grading and building plans.

AQ-1b. Measures to Reduce NO_x Emissions From Construction. The following measures shall be implemented to reduce diesel emissions:

- All diesel-powered equipment shall use ultra low sulfur diesel fuel;
- Diesel catalytic converters, diesel oxidation catalysts, and diesel particulate filters, as certified and/or verified by the EPA or the State of California, shall be installed at the guidance of the SBCAPCD, if available;
- Diesel-powered equipment shall be replaced by natural gas or electric equipment whenever feasible;
- Idling of heavy-duty diesel trucks during loading and unloading shall be limited to five minutes; auxiliary power units shall be used whenever possible. Construction worker's trips shall be minimized by requirements for carpooling and by providing lunch on site;
- Heavy-duty diesel-powered construction equipment manufactured after 1996 (with federally mandated "clean" diesel engines) shall be utilized wherever feasible;

- The engine size of construction equipment operating simultaneously, shall be the minimum practical size;
- The number of construction equipment operating simultaneously shall be minimized through efficient construction management practices to ensure that the smallest practical number is operating at any one time;
- Construction equipment shall be maintained per the manufacturers' specifications;
- Engines meeting the Tier 2 or 3 Federal emissions standards for non-road applications shall be used;
- Construction equipment operating on site, shall be equipped with two or four degree engine timing retard or pre-combustion chamber engines; and
- Catalytic converters shall be installed on gasoline-powered equipment, if feasible.

AQ-1c. Measures to Further Reduce NO_x Emissions From Construction. Engines meeting the Tier 3 Federal emissions standards for non-road applications shall be used, so that the emissions for all Project construction activities would be under the 25 tons in any 12-month period.

Rationale for Mitigation

Various filters, catalysts and pre-combustion devices reduce NO_x, ROC, CO and PM emissions from diesel engines. Also, use of newer diesel engines or replacement with cleaner natural gas engines or electric motors would reduce emissions from construction equipment. When emissions factors for Tier 3 non-road diesel engines are used to estimate all the pipeline construction equipment, NO_x emissions would be below the trigger for Rule 202, as shown in Table 4.3-12.

Emission reductions achieved through the implementation of Mitigation Measures (MM) AQ-1a-c would reduce emissions below the threshold and result in potentially significant impacts (Class II).

Table 4.3-12
Total Mitigated Construction Emissions

	Peak Day Emissions (lbs/day)					Annual Emissions (tons/yr)				
Construction Phase	**CO**	**ROC**	**NO_x**	**SO_2**	**PM_{10}**	**CO**	**ROC**	**NO_x**	**SO_2**	**PM_{10}**
EOF Construction	261	22	50	2.6	32	18.64	1.81	2.57	0.11	0.75
Pipeline Construction	510	37	188	9.0	42	36.44	2.80	10.17	0.40	2.91
Offshore Power Cable Installation	565	140	1423	30.7	136	3.33	0.67	4.65	0.10	0.43
Platform Holly Modifications	164	31	299	6.2	28	6.41	0.78	6.42	0.15	0.59
EMT Demolition	271	23	124	6.3	65	10.46	1.62	7.39	0.22	0.75
EMT Soil Remediation	42	7	35	1.3	17	0.63	0.09	0.64	0.03	0.08
Total Emissions						75	7.7	31	1.0	5.4
Total Emissions w/o EMT						64	6.0	23	0.7	4.6
Significance Criteria						na	25	25	na	na

Note:
** Demolition Emissions (EMT and mooring removal) would be exempt from the SBCAPCD rule requiring offsets.
Mitigation includes the use of Tier 3 engines.

Impact AQ-2: Increase in Emissions from Operations

The Proposed Project could potentially result in increased operational emissions at the EOF and Platform Holly (Less Than Significant, Class III).

Impact Discussion

Increases in emissions from the proposed Project operation would occur from the new equipment and increased use of the existing equipment, due to the increased oil and gas throughput. Emissions would increase due to the following:

- Increase in drilling equipment use;
- Storage and handling of dry bulk materials used for drill muds preparation;
- Off- gassing of drill muds as they come up to the surface and are recycled;
- Additional trips of supply and crew boats between Ellwood Pier and Platform Holly to assist drilling;
- Installation at the EOF of four Jenbacher 620 power generation units fueled by the process gas and natural gas;

- Higher use of LPG loading racks due to higher production;
- Increased throughput at EOF crude storage tanks;
- Installation of a new pig launcher for the oil pipeline to LFC; and
- Addition of piping and a new PSA unit that would handle CO_2 removal at the EOF.

Some emissions would be eliminated due to removal of combustion equipment and piping, change in use of some equipment, and replacement of some combustion equipment with electric equipment. The following emissions-reducing changes would occur at the Project facilities due to the proposed Project:

- Removal of combustion devices on heater treaters HT-201, HT-203 and process heater H-204 at the EOF;
- Decreased use of H-205, H-206 and H-207;
- Installation of the new low-NO_x burners on the H-205 thermal oxidizer at the EOF;
- Elimination of TK-101 emulsion breaker tank;
- Elimination of the NGL loading rack;
- Removal of all equipment from EMT and barge mooring;
- Abandonment of the Line 96 pipeline between the EOF and EMT;
- Elimination of oil transportation by barge;
- Removal of three natural gas fueled power generators that support drilling equipment on Platform Holly; and
- Installation of a new ESP powerhouse at Platform Holly.

Table 4.3-13
Assumptions for the Proposed Project Emission Sources

EOF
Project fugitive emissions from the existing components and valves would not change (in fact, they may decrease due to improvements to Lo-Cat valving and drain connections, or replacements to the flash drum V-1206 and repairs to the T-1902 and T-1903 tanks leaking walls and roofs proposed for the Project).
Fugitive emissions would increase due to the new pipeline pigging stations and components on the three additional PSA vessels at the EOF.
Fugitive emissions would be the same from the new power generators and associated natural gas components/valving as the components/valving of the existing three heater treaters (HT-201, HT-202, and HT-203) and a process heater (H-204), which would be removed. HT-202 has been used as a slop oil tank since 1999.
The new power generators fueled with process gas would operate 100 percent of the time; peak day would include all four generators operating.
The EOF oil storage tank's fugitive emissions would increase to maximum throughput.
Daily number of gas liquids trucks and thus peak day LPG loading emissions would not change; annual amount of gas liquids loading would increase with a proportionate increase in fugitive LPG loading emissions. NGL loading emissions would be eliminated
Daily number of sulfur trucks would not change (daily number of trucks is equivalent to the removal of the full sulfur storage volume); annual number of trucks would increase by 302.
Emergency fire pump and emergency generator emissions stay the same.
Flare (thermal oxidizers) emissions would decrease to an estimated 30 days at maximum throughout per year due to the available use of generators. Only pilot and unplanned flaring would occur from H-206 or H-207. All planned flaring would be directed to H-205.
Solvent/cleaning emissions would stay the same.
One pigging event per month for the new pipeline from the EOF to LFC.
No increase of commuter trips, because there will be no increase in employment at the EOF.
PLATFORM HOLLY
No increases in fugitive emissions due to the proposed wells, because the proposed wells would use the same well slots and connections as are currently in operation on Platform Holly.
No increase in the boom boat operations.
No change in the number of pigging events.
No increase in the crew or supply boat operations during normal (no drilling) operations.
During the proposed drilling, the supply boat will have an increase of three roundtrips per day.
Power generators (support electric drilling equipment) emissions would cease (power will be provided from the EOF).
DRILLING
Drilling would be conducted for a maximum of five wells per year, 25 days per well
Coiled Tubing Unit is part of the baseline (it is used for well workovers). Peak day emissions due to drilling will not include coiled tubing unit. Annual drilling emissions would increase for an equivalent of drilling up to five new wells per year.
All electrical drilling equipment would be powered through EOF-produced electricity, the electric generators would be removed, and thus no emissions from those units would occur.
Additional emissions from drill mud outgassing when they are recycled to be reused for drilling.
Additional emissions from handling of dry bulk materials for drill mud preparation.
Assumes that the drilling would be conducted in a manner that would keep the drilling equipment in the exempt category (according to SBCAPCD Rule 202.F.6), i.e., annual emissions of any criteria pollutant would be 25 tons per 12 calendar months or lower.

Assumptions that were used for estimating the Project's emissions are listed in Table 4.3-13 above.

Although emissions would increase at the EOF due to the installation of the natural gas powered generators, the peak day emissions of ROC and PM_{10} for the whole Project would be reduced (see Table 4.3-14). This is due to the emission reductions associated with the removal of the EMT and cessation of barge operations. As the EMT might be removed in 2013 or 2016, depending on lease arrangements, the emissions reductions associated with the removal of the EMT operations would occur earlier than 2016 under the proposed project.

Peak day NO_x, carbon monoxide and SO_2 emissions would increase for the Project, but would be below the thresholds of significance.

Annual emissions would increase for all pollutants. The increase in emissions is primarily due to increased use of drilling equipment and the increased use of supply boats.

Increases in vehicle emissions would be associated with the drilling phase only. Increases would be less than the threshold of 25 lbs/day for NOx and ROC. Refer to the Appendix E, Air Quality, of this EIR for more information.

Under the SBCAPCD rules, any new or modified source would be required to review its emissions, and provide emission offsets according to SBCAPCD Rules 801 (New Source Review), 802 (Non-attainment Review), and 804 (Emission Offsets). The new or modified source SBCAPCD rules do not apply to increases in emissions from mobile sources such as support trucks, commuter vehicles, or increases of emissions from the existing permitted sources within the permitted levels when no modification to those sources occurs. However, according to Rule 802, if the new emission sources are above the trigger of 25 lbs/day for NOx or ROC, the entire Project (the new and existing components) is subject to Best Available Control Technology (BACT).

Mitigation Measures

None required.

Table 4.3-14
Estimated Proposed Project Operational Emissions

	Peak Day Emissions (lbs/day)					Annual Emissions (tons/yr)				
Phase	**NO_x**	**ROC**	**CO**	**SO_2**	**PM_{10}**	**NO_x**	**ROC**	**CO**	**SO_2**	**PM_{10}**
Total Current Operations	**1053**	**2628**	**925**	**147**	**102**	**93**	**157**	**82**	**13**	**7**
Proposed Operations										
EOF	102	829	759	31	34	11	164	76	1.4	4.1
Platform Holly, Operations	25	154	38	57	3.2	4.4	29	3.5	0.8	0.4
Platform Holly, Drilling	350	28	75	4	24	19	1.5	4.0	0.2	1.3
Crew and Supply Boats	606	23	90	61	35	111	4.1	16	11	6.3
EMT and Vessels and Barge *Jovalan*	0	0	0	0	0	0	0	0	0	0
Total Proposed Operations	***1084***	***1034***	***962***	***152***	***96***	***145***	***199***	***100***	***13***	***12***
Total Increase/Decrease	**31**	**-1594**	**37**	**5**	**-6**	**51**	**42**	**18**	**0.2**	**5**
Threshold	55	55	150	55	80	-	-	-	-	-
Exceeds Threshold?	**No**	**No**	**No**	**No**	**No**	-	-	-	-	-

Notes: Threshold based on SBCAPCD Rule 802, section E, Table 3 daily emissions

Impact AQ-3: Odor Emissions from Operation

The Proposed Project could result in increased potential for an upset event with a subsequent gas release or an oil spill, and thus could potentially result in increased nuisance odor events (Potentially Significant, Class II).

Impact Discussion

The areas immediately adjacent to the EOF are used for recreational purposes. In addition, there is the Bacara Resort and Spa adjacent to the EOF on the west. With these two considerations, the release of odorous compounds, such as H_2S or petroleum gases, could create nuisance odors, which would be considered a significant impact.

In the past several years, due to the breakdowns and leaks at the EMT storage tanks, there have been an increased number of odor complaints in regards to operations at the EMT facility. Odors from the EMT and the Barge *Jovalan* would cease with the removal of the terminal and barge mooring. This would constitute a beneficial impact.

Current operations to reduce odors includes the use of the thermal oxidizer, H-205, which is used to incinerate potentially odorous gases from various processes at the EOF, primarily the LOCAT oxidizer exhaust air. According to the SBCAPCD Permit 7904-R7, the thermal oxidizer, H-205, is required to achieve a 98.5 percent destruction rate with combustion temperatures close to 1400°F. Under the proposed Project, the

LOCAT oxidizer exhaust air would be combusted by the Jenbacher generators instead of the H-205. The Applicant states in the application that the generators would supply sufficient odor control. However, no specific calculations have been provided to demonstrate that there would be a sufficient temperature and residence time to ensure a 98.5 percent destruction rate. This information would be required in order to obtain a permit from the SBCAPCD. The emissions of LOCAT gases with less than the required destruction efficiency level could produce odors and would be potentially significant.

Potential oil spills and gas releases at the EOF could create objectionable odors due to evaporation of odorous compounds (H_2S and ROC) from the spilled oil surface or from the released gas and, thus, could generate odor complaints.

Any increase in odorous compounds releases would be a significant impact and potentially could be a violation of SBCAPCD Rule 303, Rule 325 and Rule 310.

Mitigation Measures

AQ-3a. Ensured Destruction Efficiency of LOCAT Gas. The Applicant shall continuously route the LOCAT gas stream to the H-205 consistent with the requirements of the Santa Barbara APCD Permit to Operate 7904 unless it can be clearly demonstrated to the satisfaction of the APCD that the Jenbacher engines can produce the required level of LOCAT gas destruction and avoid odor impacts.

Rationale for Mitigation

The current PTO 7906-R7 includes detailed analysis indicating that the H-205 can produce a residence time and temperature for the LOCAT gases that would meet a 98.5 percent destruction efficiency. This level of destruction has been determined by the SBCAPCD to be required to avoid odor impacts. The Application includes qualitative statements that the Jenbacher engines would be able to provide this same level of control. However, no detailed engineering analysis has been provided. Ensuring that the Jenbacher engines can provide the required destruction efficiency would be a requirement for utilizing the LOCAT gases in the Jenbacher generators. If the Jenbacher generators cannot produce the required destruction efficiency levels, then the LOCAT gases shall continue being combusted in the H-205 heater as is currently operated.

If the facility were to operate utilizing the H-205 heater instead of the Jenbacher engines for LOCAT gas destruction, it would increase the annual load on the H-205 heater to an estimated 80% from the estimated 30 days per year which H-205 might operate under the proposed project. Assuming the Jenbacher engines continue to operate at the same level as in the proposed project, this would increase the H-205 throughput by a factor of 10 on an annual basis. However, as the peak daily emission from the H-205 would not increase and the installation of low-NO_x burners would reduce emissions, this would still not be considered a significant impact. Please see Appendix E.

With the demonstration of the ability of the Jenbachers or the change in design to allow the H-205 heaters to continue their current operations, the impacts would be potentially significant (Class II).

Impact AQ-4: Increase in Health Risk

The proposed Project could potentially result in increased HAP emissions from the facilities and thus increase health risk (Potentially Significant, Class II).

Impact Discussion

Health risks associated with the proposed Project were evaluated using the most recent version of Hotspots Analysis and Reporting Program (HARP 1.3). A revised baseline analysis was conducted, which included recent modifications to the equipment and operations. An HRA for the revised baseline and proposed Project were performed for Platform Holly, the EMT (for revised baseline only), and EOF together, and for Platform Holly and the EOF together. The results are summarized in Table 4.3.15. For more details refer to the Air Quality Appendix of this EIR.

Health risks associated with the EMT would be eliminated when the terminal is shut down in favor of pipeline transport of crude oil. Health risks associated with the EOF and Holly are similar for the proposed Project and the revised baseline because the impacts are driven by only a few pieces of equipment (the emergency generator at the EOF and supply boats that originate at Ellwood Pier), which would not change with the proposed Project.

The Project's health risks are substantially above the thresholds for areas offsite. However, because the proposed Project's worst-case impacts are well above the respective thresholds for cancer risk and acute impacts in areas of potential public exposure, the health risk impact would be considered potentially significant (Class II).

Table 4.3-15
Proposed Project and Mitigated Proposed Project HRA Results

Facility	HRA	Cancer Risk per million (Threshold = 10 per million)	Non Cancer Risk Index	
			Chronic (Threshold = 1)	Acute (Threshold = 1)
EMT, EOF and Holly	Revised Baseline	32.1 (significant)	0.10 (not significant)	1.13 (significant)
Platform Holly and EOF	Project	36.6 (significant)	0.056 (not significant)	1.13 (significant)
	Mitigated Project	9.1 (not significant)	0.04 (not significant)	0.55 (significant)

Notes:
The Platform Holly acute HI of 6.0 would not change with the proposed project since this value is the result of peak hourly emissions from the supply boats.
Ellwood's risk is not considered significant because it occurs within the facility's easement, the public does not have access to that area and there are no residents within the isopleths.
Mitigated project includes the installation of catalysts on the emergency generator achieving 90 percent reduction in ROC and PM and the installation of catalysts on the supply boat engines.

Mitigation Measures

AQ-4a. Diesel Oxidation Catalyst. The Applicant shall install a diesel oxidation catalyst (DOC) on diesel-combusting equipment that contributes to health risk. The DOC shall achieve 90% reduction of PM and ROC emissions. Applicable equipment shall be determined by the SBCAPCD.

Rationale for Mitigation

Potential health risks are almost completely the result of diesel particulate exhaust from the emergency generator at the EOF and supply boats the Ellwood Pier.

The use of a DOC on the emergency generator would reduce potential health risks in areas of public exposure. Diesel catalysts, such as those available from Johnson Matthey, have demonstrated ROC and PM reductions of 90 percent. This would reduce the health risk impacts at the EOF to the levels shown in Table 4.3-15. Installation of the DOC technology would reduce health risks from supply boats. The HRA impacts with mitigation are below the significance thresholds and the impacts would be potentially significant (Class II).

Impact AQ-5: Increase in Greenhouse Gas Emissions

The Proposed Project would produce higher greenhouse gas emissions and contribute to climate change (Potentially Significant, Class I).

Due to the drilling, new equipment, the addition of onsite electrical generation and the increase in operations of the existing equipment, direct emissions of GHGs would increase. Indirect emissions associated with offsite, grid based electrical generation would decrease due to the installation of onsite electrical generation. Emissions of GHGs were estimated using the same operating assumptions used to estimate criteria emissions from the proposed Project.

The direct GHG emissions at the EOF and Platform Holly would come from the combustion of natural gas and diesel fuel (producing GHG emissions composed of primarily CO_2), from onsite generation of electricity, as well as from fugitive emissions (a component of fugitive emissions is methane, CH_4).

Indirect emissions would be associated with truck transportation offsite and from the generation of offsite, grid based electricity. Grid based electrical GHG emissions are based on the CALISO weighted average values obtained from the EPA eGRID database (excluding the Mojave Coal power plant). Although the Project would increase the total use of electricity, due to the installation of onsite power generation, the power imported from the California grid would decrease.

Table 4.3-16 below summarizes the GHGs emissions due to the proposed Project. Note that these are project specific emissions (direct and indirect) and do not include emissions changes in the lifecycle of product movements. These emissions are discussed below.

Due to the net increase of GHGs by the proposed Project over baseline, this impact is considered significant (Class I).

Lifecycle Analysis: Crude Oil and Natural Gas End-use

The lifecycle analysis addresses potential changes to operations of facilities downstream of the EOF. This would include emissions from transportation of the crude oil to area refineries, changes to the crude oil markets that could result from the production of additional California crude oil, refinery emissions and end-use emissions.

The crude oil produced from the proposed Project would be delivered to Los Angeles area refineries and refined into gasoline, diesel, jet fuel, and a range of other end products. GHG emissions would be associated with the transportation, refining and end-use of the refined products, including natural gas, propane and crude oil after it has been processed and distributed. Natural gas would be burned in homes, businesses and to produce electricity. Propane would be used for residential uses (heating, barbeques, etc.), transportation, and industrial fuel.

Table 4.3-16
Greenhouse Gases Emissions Summary, Annual Emissions tons/yr

Emission Source	Proposed Project		Current Emissions	
	CO_2	CH_4	CO_2	CH_4
Construction Emissions	2,468	5.3	na	na
Operational - Direct Emissions				
EOF				
Combustion (HT-201 thru HT-204 or due to onsite electrical generation)	74,022	1	10,163	0.12
Combustion – flares (H-205 thru H-207)	2,025	0.01	11,577	0.24
Fugitives	0	9	0	9
Other	8	0	8	9
Platform Holly				
Combustion (drilling engines and generators)	854	0	1,525	0.03
Combustion - flare	785	0	785	0.02
Crew and Supply Boats	4,406	0	2,773	9
Fugitives	0	3	0	3.05
Others	156	0	156	9
EMT (tug, assist and ER boats)	0	0	198	3.00
Barge at Ellwood	0	0	85	0.31
Barge Transport to LA/SF Bay Area	0	0	6,673	9
Total Direct Emissions	**82,257**	**13**	**33,943**	**16**
Operational - Indirect Emissions				
Electrical Generation	5,401	0	18,852	0
Offsite Vehicles	827	0	496	0
Operations Total Indirect Emissions	**6,228**	**0**	**19,347**	**0**
Operations Total GHG Emissions	**88,485**	**13**	**53,291**	**16**
Operations Total CO_2-e, tons/year	**88,760**		**53,620**	
Operations Total CO_2-e, metric tonnes/year	**80,690**		**48,745**	
Project Specific Operations Net Increase/Decrease, CO_2-e, tons/year	**35,140**			

Notes:
Electrical generation assumes CALISO weighted average GHG emission rate.
CO_2-e is CO_2 equivalent emissions, which includes methane emissions times 21 (the GWP).
To convert to metric tonnes of GHG from tons, multiply by 0.90.

However, the Project would not increase the consumption of these refined products as the consumption of gasoline, natural gas, propane and crude oil products is not a function of the source of the gas or crude oil supply. Therefore, there would be no net increase in lifecycle GHG emissions associated with the proposed Project end-use products over current production related lifecycle GHG emissions. The following information on end-use is for informational purposes only.

GHG emissions associated with the consumption of natural gas produced by the proposed Project, including residential cooking and heating, business and industrial use and electricity generation, would be an estimated 723,000 tons per year. This is above the current facility's natural gas production end-use amount of 289,000 tons per year. Note that the natural gas is processed and introduced into the end-use pipelines (owned by The Gas Company) near the EOF.

GHG emissions associated with the end-use of propane would total about 61,000 tons/year. This is above the current facility's production end-use amount of 24,000 tons per year.

GHG emissions associated with the end-use of crude oil produced from the Ellwood field, including gasoline, diesel fuel, jet fuel, residual oils, etc, would total about 2.4 million tons/year (API 2004). This is above the current facility's production end-use amount of 600,000 tons per year.

GHG emissions associated with refining the above listed propane and crude oil would produce estimated GHG emissions of 320,000 to 420,000 tons/year, or 13 to 17 percent of the total end-use product amount (GM 2001).

In addition, refining of crude oil produces by-products, such as "coke" and bunker fuels, which are the heavier products that result from refining crude oil into lighter products, (i.e., gasoline). Coke and bunker fuels are normally exported from California ports to other countries where they are burned in either electric power generation plants or engines. These by-products would be generated regardless of the source of the crude oil and are therefore a part of both the lifecycle baseline emissions as well as the Project lifecycle emissions and were not included in the GHG emissions estimates.

Mitigation Measures

Methods to reduce or offset GHG emissions are associated with facility and project changes, as well as programs that the Applicant could sponsor in the community to offset the facility GHG emission increase.

AQ-5a. GHG Emission reduction program. The Applicant shall implement a program to reduce GHG emissions from project components and/or community sources to achieve a net zero increase in GHG emissions from the project. Possible GHG emissions reduction could be achieved through the following programs:

- Reduce energy consumption from facility sources to the maximum extent feasible, including reduced generator use and gas production, high efficiency motors and pumps and installing high efficiency lighting;
- Reduce facility water consumption, waste generation and raw materials usage, and utilize recycling, to the maximum extent feasible;
- Use of bio-diesel or bio-diesel blends for diesel equipment;
- Sponsor the retrofit of diesel buses with hybrid engines;
- Sponsor methane capture technology projects, including methane capture from dairy and/or agricultural operations;
- Capture of methane emissions from area seeps; and
- Planting of trees to offset carbon emissions.

Rationale for Mitigation

Reduction of energy use, including natural gas and electricity, from existing and proposed direct sources would reduce GHG emissions from fuel combustion and electrical generation. Reducing water, raw material use, waste generation and increasing recycling, would reduce GHG emissions by reducing the energy used to transport/pump water and to produce goods, and truck trips, with associated diesel fuel combustion, to produce and transport waste and materials.

In addition, the majority of the GHG emissions associated with the project are produced from the generators at the EOF. Although the generators are utilized to produce heat for crude treatment and to produce electricity for operations, the use of the generators increases the EOF GHG emissions associated with combustion by more than a factor of three. More efficient gas processing so that less gas is required to be used by the generators, reduction in electrical demand of equipment so that fewer generators would be needed and more efficient heat transfer systems so that less heat is required, could reduce the GHG emissions associated with the generators. Although detailed design analysis would be required in order to maximize the energy efficiency and heat and electrical generation, a reduction on the order of 10 percent would reduce emissions of GHG by 6,000-7,000 tons CO_2e annually.

Biodiesel (fatty acid methyl ester or FAME) is produced from plant crops, such as soybeans. Because it is made from plant sources, the carbon in the biodiesel has been recently removed from the atmosphere and therefore does not contribute to GHG emissions. It can be used by current diesel vehicles (UC 2007). The American Society of Testing and Materials has approved a standard for FAME at blend levels up to 20 percent by volume but some engine manufacturers caution about blends over 10 percent. Replacement of 10 percent to 20 percent of the diesel fuel with biodiesel would reduce GHG emissions by a similar amount. Biodiesel could be used in project equipment or could be used in other area engines, such as school buses, to offset direct emissions from the Project. Replacement of supply and crew boat and offsite truck diesel fuel with 10 percent biofuels would save about 500 tons per year of CO_2.

Replacing existing diesel buses with buses powered by more efficient diesel-hybrid engines would decrease GHG emissions through an increase in the fuel economy and efficiency and an associated decrease in fuel combustion. Diesel-hybrid buses employ technology including regenerative braking, electric motors, and battery storage to increase fuel efficiency. Experiences in New York City indicate fuel economy efficiencies averaging 26 to 52 percent better than regular diesel buses (NREL 2006). As an example, the Santa Barbara Metropolitan Transit District (MTD) currently has eight Gillig diesel-hybrid buses out of a total of 83 regular diesel buses. The bus fleet logs almost 2.5 million annual miles, using an estimated one million gallons of diesel fuel and generating close to 11,000 tons per year of CO_2 emissions. By replacing the entire MTD fleet with diesel-hybrid buses, there would be a reduction in CO_2 emissions of about 3,000 tons annually.

In addition, replacing local school busses with diesel-hybrid busses and/or ensuring that school buses operate on biofuels at 10% would reduce GHG emissions.

Methane capture is currently a promising technology that would enable the conversion of methane emissions from livestock manure into fuel. This would reduce GHG emissions by taking advantage of the GWP difference between CH_4 and CO_2 (as use of the methane as a fuel would produce CO2). A study conducted by a range of agencies and industry representatives (SJVDMTFAP 2005) concluded that it was "unable to determine the environmental and economic performance of most of the [methane capture] technologies." The study indicated there are existing problems due to salts and wastewater issues that would need to be solved and the study recommended the development of additional pilot projects. However, studies conducted by the California Climate Action Registry (CCAR) indicate that anaerobic digesters are used at some dairies in California and at over 80 locations nationwide; and that increased use could substantially reduce GHG emissions. Methane capture from livestock manure could save an estimated 6 tons per year of GHG CO_2 equivalent (CH4 having a GWP of 21) per livestock unit (CCAR 2007). Given that there are about 1.7 million dairy cows in California (see section 3.0, Alternatives), 60 percent of them on feed lots, this equates to a potential savings in GHG CO_2 equivalent emissions of over 6 million tons annually from California feed lot dairy cows.

Capture of methane from the natural gas seeps located in the Santa Barbara channel would allow for processing and combustion of the methane gas, thereby reducing GHG emissions due to the difference in global warming potential between methane (GWP of 21) and CO_2 (GWP of 1). Studies conducted by UCSB estimate that close to 350,000 CO_2-e tons per year are emitted from the Coal Oil Point seep fields. Two seep fields studied by UCSB (Washburn 2005), the Horseshoe and the Shane seeps, generate an estimated 25,000 and 18,000 tons CO_2-e per year, respectively. The existing seep tent near Platform Holly captured an annual average of 155 mmscf between 2001-2005 (SBC Energy Division data). This equates to a savings of about 60,000 CO_2-e tons per year. The installation of additional seep tents at the Horseshoe, Shane or other seeps could be a significant source of GHG emission reductions with proven technology.

Planting of trees removes CO_2 from the atmosphere as the tree grows. Trees remove CO_2 from the atmosphere through photosynthesis and store or "sequester" the carbon in the tree trunk, branches and leaves. Trees serve as effective carbon sinks since about one-half of the dry weight of the wood is carbon. Forests store more carbon dioxide than the entire atmosphere (IPCC 2007). CO_2 sequestration rates vary by tree type and by land type/quality up to about 10 tons per acre. Tree planting for GHG emission reductions is somewhat controversial as the trees only store/sequester the carbon until they are fully grown. When they die and decay or are used for fuel, they release the carbon they have absorbed while growing. Tree forests for GHG emission reductions must be managed and maintained and new trees must be grown to replace trees that have died in order to maintain the sequestration of the carbon. According to the Intergovernmental Panel on Climate Change, on the global level, 12 to 15 percent of total global carbon emissions per year could be managed through forestry activities.

GHG emissions from indirect sources (grid electricity generation through CALISO) are currently addressed through CPUC Emission Performance Standard policies (Commission's Rulemaking on Greenhouse Gas policies R.06-04-009) and Senate Bill 1368, requiring that electricity generators produce power more efficiently, with an efficiency equal to or below a combined cycle gas turbine (1,100 lbs CO_2/MWh). This would lower the GHG emissions from the electric resource mix, since GHG emissions associated with electrical generation from coal and gas would be lowered (currently 2,100 and 1,235 lbs/MWh, respectively, for the CALISO area), and would address the reduction in greenhouse gases from indirect electrical generation.

Residual Impacts

With the application of a number of the recommended mitigation measures, the GHG emissions will still be above the thresholds value of no net increase in GHG emissions (Table 4.3-17). This would be considered a significant impact (Class I).

Table 4.3-17
Summary of Greenhouse Gas Emission Mitigation Measures

Impact	Mitigation Measures Effectiveness, CO_2-e tons/year reduction
Increase EOF/Holly Efficiency and reduced generator operations	6,000 – 7,000
Methane Capture from Seeps	18,000 – 25,000
Biodiesel in supply boats	500
Community projects (MTD diesel-hybrid, school bus modifications, livestock methane capture, etc)	> 3,000
Total Potential Reductions	> 27,500 – 35,500
Reductions needed (Table 4.3-16)	35,140

Extension of Life Impact

The Applicant has stated that the proposed Project would not increase the life of the existing South Ellwood Field Facilities, which is currently defined by the operational life of Platform Holly until 2040, and would likely reduce the overall duration of oil and gas production from existing facilities due to more efficient extraction of the resource. However, it is possible that increased oil and gas production from new wells drilled into the existing and proposed leases, formations (Lower Sespe) and fault blocks (North Flank and Eagle Canyon) could produce economically viable resources for a longer-than-expected period and increase the life of the existing facilities. Therefore, the impacts identified in Table 4.3-18 have the potential to occur over a longer period than assumed for the proposed project, exacerbating potentially adverse impacts.

Increasing the project duration and continued operation of facilities that emit air pollutants resulted in continued exposure of the public to air pollution and would be considered potentially significant (Class I).

Table 4.3-18
Summary of Air Quality Impacts and Mitigation Measures

Impact	Impact Class	Mitigation Measures
AQ.1: Construction Emissions	Class II	**AQ-1a.** Dust Emission Reduction. **AQ-1b.** NOx Emission Reduction. **AQ-1c.** Tier 3 Engines for Pipeline Construction.
AQ.2: Operations Emissions	Class III	None required.
AQ.3: Odor Emissions from Operations	Class II	**AQ-3a.** Ensured destruction efficiency of the LOCAT Gases
AQ.4: Project Health Risk	Class II	**AQ-4a.** Diesel Oxidation Catalyst.
AQ.5: Increase in Greenhouse Gas Emissions	Class I	**AQ-5a** Programs to reduce GHG emissions from facility and community sources.

4.3.5 Impacts Of Alternatives

No Project Alternative

Under this Alternative emissions from the EOF, Platform Holly and the EMT would be the same as the current operations.

Currently, lease agreements for the operations of the EMT will expire in 2013 and/or 2016 (see Section 2.0, Project Description). It is assumed that under the No Project Alternative, after the lease expirations, the Applicant would pursue alternative means of crude oil transport such as pipeline or truck transportation. The impacts of these transportation modes are described in the Venoco Ellwood EMT Lease Renewal Project Final EIR (CSLC 2007). The EMT EIR indicated that annual emissions associated with trucking would be greater than current operations, but peak daily emissions from the trucks would be lower than the peak day emissions from current operations. Any future crude oil transportation options would be subject to appropriate agency review and approval.

No EOF Modifications

Construction emissions would be reduced if no new equipment is installed at the EOF; and, thus, Impact **AQ-1** would be less severe.

Operational emissions of NOx would increase at the EOF as the heater treaters and thermal oxidizers would have to be used at almost full load to process the estimated amount of permeate gases generated by the increased production levels. As the heater treaters and thermal oxidizers do not have NOx controls as stringent as SCR units, the NOx emissions would be higher under this alternative. The overall emissions of ROC would still decrease due to the removal of the EMT, but would be less than the proposed Project due to the use of existing equipment. Emissions are summarized in Table 4.3-19. However, emissions are still less than the thresholds and would be less than significant. NOx emissions, with offsets, could still be reduced further. Refer to the Appendix E, Air Quality, for more details.

Table 4.3.19
The "No Modifications at EOF" Alternative Operational Emissions

	Peak Day Emissions (lbs/day)					Annual Emissions (tons/yr)				
Phase	**NOx**	**ROC**	**CO**	**SO_2**	**PM_{10}**	**NOx**	**ROC**	**CO**	**SO_2**	**PM_{10}**
EOF	151	524	590	52	19	27	109	122	10	3.6
Platform Holly, Operations	25.9	154	38	57	3.2	4.4	29	3.5	0.8	0.4
Platform Holly, Drilling	377	73	227	11.4	48	36	10.6	34.2	1.7	6.5
Crew and Supply Boats	606	23	90	61	35	111	4.1	16	11	6.3
EMT and Vessels and Barge *Jovalan*	0	0	0	0	0	0	0	0	0	0
Total Alternative Operations	**1160**	**774**	**944**	**181**	**106**	**178**	**153**	**176**	**24**	**17**
Increase/Decrease over Proposed Project	**76**	**-260**	**-18**	**28**	**10**	**33**	**-46**	**76**	**11**	**5**

Health risk impacts would be similar to the proposed Project. In the absence of mitigation, potential health risks would be considered significant. However, implementation of mitigation measures **AQ-4a** would reduce potential health risks to acceptable levels in areas of public exposure. Therefore, mitigated health risks would be less than significant as shown in Table 4.3-20.

Odor emissions would also be similar to the proposed Project impacts. However, as the H-205 heater would continue to be used for LOCAT gas destruction, Impact **AQ-3** and mitigation measure **AQ-3a** would no longer apply.

GHG emissions would be marginally less than the proposed Project due to the increased use of electricity from the CALISO grid, as electricity would not be generated at the EOF. As much of the CALISO electricity comes from hydro and nuclear, which does not generate GHG emissions, there would be a reduction in GHG emissions with this alternative. However, potential impacts would remain significant.

Table 4.3-20
No EOF Modifications Alternative and Mitigated HRA Results

Facility	HRA	Cancer Risk per million (Threshold = 10 per million)	Non Cancer Risk Index	
			Chronic (Threshold = 1)	Acute (Threshold = 1)
Platform Holly and EOF	No EOF Modifications	47.1 (significant)	0.16 (not significant)	1.13 (significant)
	Mitigated Alternative	20.8 (not significant)*	0.14 (not significant)	0.55 (not significant)

Notes:
* Alternative risk is not considered significant because it occurs within the facility's easement, the public does not have access to that area and there are no residents within the isopleths.
Mitigated Project includes the installation of catalysts on the emergency generator achieving 90 percent reduction in ROC and PM and the installation of catalysts on the supply boat engines.

Processing on Platform Holly

Under this scenario, processing equipment would be removed from the EOF and new processing equipment installed on Platform Holly. Since the same amount of processing would take place, potential air quality impacts would be similar to the proposed Project. Emissions would be similar assuming that SCR or other catalytic reduction of NOx would be installed on the fuel combustion equipment at the platform. If no generation is used, then the advantages of co-generation (production of both heat and electrical power) at the platform would not be realized and NOx emissions would increase to levels similar to the "No Modifications at EOF" alternative discussed above. Given that the installations on Platform Holly associated with this alternative would be new, the SBCAPCD would most likely require Best Available Technology (BACT) to be used, which would reduce emissions to levels similar to the proposed Project.

Impact AQ-6: Construction and Demolition Emissions

There would be increased emissions from construction at the platform and demolition at the EOF (Potentially Significant, Class II).

Impact Discussion

Construction emissions associated with abandonment of the EOF would be similar in nature and magnitude as that of the EMT abandonment, described in **AQ-1** above. While the level of potential soil contamination at the EOF is unknown, it is possible that soil remediation would be required necessitating excavation and trucking at the level estimated for the EMT demolition.

Mitigation Measures

Implement Mitigation Measures **AQ-1a** through **AQ-1c**.

Emission reductions achieved through the implementation of Mitigation Measures (MM) **AQ-1a-c** would reduce emissions below the Rule 202 threshold and result in potentially significant impacts (Class II).

Health risk impacts would be similar to the proposed Project. In the absence of mitigation, potential health risks would be considered significant. However, implementation of **MM AQ-4a** would reduce potential health risks to acceptable levels. Therefore, after mitigation, health risks would be less than significant as shown in Table 4.3-21.

Table 4.3-21
Processing on Platform Holly Alternative and Mitigated HRA Results

Facility	HRA	Cancer Risk per million (Threshold = 10 per million)	Non Cancer Risk Index	
			Chronic (Threshold = 1)	Acute (Threshold = 1)
Platform Holly and EOF	Platform Holly Processing	35.8 (significant)	0.04 (not significant)	1.13 (significant)
	Mitigated Alternative	9.0 (not significant)	0.02 (not significant)	0.55 (not significant)

Notes:
Mitigated Project includes the installation of catalysts on the emergency generator achieving 90 percent reduction in ROC and PM and the installation of catalysts on the supply boat engines.

Odor impacts would be reduced due to the more remote location of gas and crude oil processing. However, as crude storage, pigging and pumping would remain at the EOF under this alternative, the odor impacts would still remain.

GHG emissions would be marginally less than the proposed Project due to the increased use of electricity from the CALISO grid over the proposed Project. This assumes that the generating requirements would utilize the existing generators installed on Platform Holly as electricity would not be generated at the EOF. As much of the CALISO electricity comes from hydro and nuclear, which does not generate GHG emissions, there would be a reduction in GHG emissions with this alternative.

As demolition of parts of the EOF would take place under this alternative, there is the potential for some asbestos impacts to occur due to possible asbestos insulation at the EOF. The presence of asbestos at the EOF has not been confirmed, but it is a possible impact of EOF removal. This would be reduced by adherence to permit requirements.

Las Flores Canyon Processing: Offshore Gas Pipeline and Onshore Oil Pipeline

Under this scenario, both oil and gas processing would be done at the LFC Plant. Produced gas, utility and return water pipelines and a power cable would need to be installed from Platform Holly to the LFC facility. Equipment removal would be conducted at the EOF. Impact **AQ-1** would be more severe than the proposed Project as more construction activities would take place due to the need for installation of an offshore gas pipeline and the removal of the EOF equipment. Applying MM **AQ-1a-c** would lessen the impacts to below significance.

Impact **AQ-2** would be different, as operational emissions at the EOF would be eliminated (except for minor fugitive emissions from the valve box on the emulsion pipeline). However, higher emissions would occur at the LFC Facility due to moving the processing from the EOF to the LFC. As the LFC also has electrical/cogeneration facilities, overall emissions would be similar to those estimated for the proposed Project.

Health risks associated with the EOF would be eliminated because the EOF equipment would be removed and no processing would occur at that location. However, higher toxic emissions would occur at the LFC Plant. As required by AB 2588, a health risk assessment (HRA) for the LFC source was prepared by the SBCAPCD on March 28, 1995. The HRA is based on 1993 emissions and was prepared by the SBCAPCD at the request of ExxonMobil.

Based on the 1993 air toxics emission inventory, a cancer risk of six per million at the property boundary was estimated for the LFC Stationary Source. The risk is primarily due to benzene and carcinogenic polycyclic aromatic hydrocarbon (PAH) emissions from a thermal oxidizer. Emissions of hydrazine also contribute to the cancer risk estimate. Hydrazine is emitted from a steam generation system. The 1993 facility-wide annual emissions were 180 pounds per year for benzene, 15.1 pounds per year for PAH, and 1.71 pounds per year for hydrazine.

In order to estimate current emissions from the LFC facilities, crude oil and gas throughputs were compared to the 1993 levels as compiled by the SBC Energy Division. Toxic emissions are roughly linear to throughput for equipment such as tank fugitives and heater/combustion sources. Crude levels in 1994 averaged 78,000 BPD and gas throughputs averaged 33 mmscfd. These throughout levels are above the current throughout levels, so that toxic emissions would be expected to be higher in 1993 than currently. Therefore, it is anticipated that a revised HRA for the LFC facilities would show similar if not lower risk levels.

In addition, an acute non-cancer hazard index of 0.3 and a chronic non-cancer hazard index of 0.1 have been estimated by the SBCAPCD (both under the significance threshold of 1.0) for the LFC using the 1993 air toxics inventory. The acute and chronic risks are due to ammonia emissions and their effect on the respiratory system endpoint (SBCAPCD 2000).

Increased processing at the LFC due to Platform Holly gas and crude oil would increase toxic emissions and the associated HRA risk levels somewhat. However, as the processing of the additional oil and gas would utilize existing equipment, health risk levels are anticipated to increase only marginally. Also, as the LFC is located remote from public areas, risks to the public are not expected to increase from the LFC under this alternative.

The LFC has experienced some odor issues in the past. In January, 2007, the LFC facility received an NOV from the SBCAPCD for a nuisance violation related to the detection of H_2S at the odor monitoring station located along Calle Real road. The odors were generated from the wastewater aeration basins (SBCAPCD NOV 8734). However, as existing equipment at the LFC would be utilized for sulfur processing, impact **AQ-3** would be eliminated.

Because the LFC has a cogeneration system, an arrangement similar to the proposed Project with respect to cogeneration would take place under this alternative. Therefore, potential GHG emissions under this alternative would be similar in magnitude to the proposed Project.

As demolition of the EOF would take place under this alternative, there is the potential for some asbestos impacts to occur similar to those discussed for the Processing on Platform Holly alternative.

Las Flores Canyon Processing: Offshore Gas and Offshore Oil Pipeline

Under this alternative, production would occur at Platform Holly, and all processing would be done at the LFC Plant. Impact **AQ-1** would increase, as more construction activities would be undertaken due to the removal of the EOF. However, as crude oil, gas, utility and return water pipelines would be placed in the same corridor and could be laid simultaneously, the construction emissions associated with pipeline installation would be similar to the proposed Project, but less than the LFC alternative with an onshore crude oil pipeline and an offshore gas pipeline as discussed above.

Impact **AQ-2** associated with operations would be different, as no operational emissions would occur at the EOF. However, higher emissions would occur at the LFC Plant and the impacts would be the same as discussed above for the LFC alternative with an onshore crude oil pipeline and an offshore gas pipeline.

Health risk at the EOF would be eliminated. However, higher toxic emissions would occur at the LFC Plant with similar impacts as discussed above for the LFC alternative with an onshore crude oil pipeline and an offshore gas pipeline.

As existing equipment at the LFC would be utilized for sulfur processing, impact **AQ-3** would be eliminated.

Increase in GHG emissions over current operations would occur due to increased processing and throughput at the LFC Plant, and the proposed drilling at Platform Holly. However, these emissions would be similar to the proposed Project (Impact **AQ-5**).

As demolition of the EOF would take place under this alternative, there is the potential for some asbestos impacts to occur similar to those discussed above.

4.3.6 Cumulative Projects Impact Analysis

There are several industrial and oil development projects proposed in the South Central Coast Air Basin (see Section 4.0, Environmental Analysis). These projects are individually likely to have significant air quality impacts and include the liquefied natural gas (LNG) terminal, (No. 2, Platform Grace/Crystal Energy from Table 4-1), the Paredon Project, and the PRC 421 Recommissioning Project. The Platform Grace/Crystal Energy LNG terminal Project is located 29 miles (46.7 km) southeast from the EMT. The Paredon Project is located approximately 25 miles (40.2 km) southeast of the proposed Project site. The Lease PRC 421 Recommissioning Project is located immediately south of the EOF on the beach; and this particular project was identified as having significant air quality impacts in its draft EIR due to barge loading and transportation of crude oil to markets. However, these impacts from PRC 421 project be eliminated by the proposed Project as crude oil would be transported by pipeline.

There are potentially significant air quality impacts that have been identified for the Project. Mitigation measures would reduce the significance of the Project's impacts to a level below the relevant significance criteria. However, the Project would still contribute to the cumulative increase in emissions in the air basin, which is currently in non-attainment for ozone.

Proposed residential, commercial, institutional, or recreational projects in the Project area would generate emissions and air quality impacts. For example, the Cabrillo Business Park, the Village at Los Carneros and the Costco Gas Station projects all do not have significant air quality impacts, but would generate emissions. Combined with these projects, the proposed Project might have cumulatively significant air quality impacts because the area is in non-attainment for ozone.

The Project would increase emissions of GHG over the current operations, and would not be mitigated to less than current GHG emissions. The other projects listed in the cumulative projects list would also most likely increase the emissions of GHGs over their respective current operations. In combination with the other projects listed, the project emissions would contribute to a regional increase in GHG emissions. Therefore, cumulative impacts are considered Significant and Unavoidable.

According to the Scope and Content of Air Quality Sections in Environmental Documents (SBCAPCD 2007), commercial or industrial projects are considered to be consistent with the 2001 and 2004 Clean Air Plans (CAP) "if they incorporate CAP Transportation Control Measures (TCM), applicable stationary source control measures, and are consistent with SBCAPCD rules and regulations." The proposed Project meets these conditions and therefore would be consistent with the CAPs.